The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 15-155 September 30, 2016

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on November 6, 2015, to be effective December 1, 2015.

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TABLE OF CONTENTS

I. INTRODUCTION

On November 6, 2015, Massachusetts Electric Company ("MECo") and Nantucket Electric Company ("Nantucket Electric"), together doing business as National Grid ("National Grid" or "Company") filed a petition with the Department of Public Utilities ("Department") for an increase in its base distribution rates for electric customers. National Grid was last granted an increase in electric distribution rates in 2009 in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39 (2009). The Department docketed the instant matter as D.P.U. 15-155, and suspended the effective date of the proposed rate increase until October 1, 2016, to investigate the propriety of the Company's petition.

MECo and Nantucket Electric are regulated investor-owned public utilities incorporated in Massachusetts (Exh. NG-MLR-1, at 23). Both companies 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 (Exh. NG-MLR-1, at 23).[1] National Grid is engaged in the retail distribution and sale of electricity across a Massachusetts service territory that serves approximately 1.3 million customers in 172 cities and towns (Exh. NG-MLR-1, at 23).

In the instant filing, the Company seeks a combined increase in base distribution rate revenues of $201.9 million (Exh. NG-RRP-2, at 1 (Rev. 3)).[2] The Company contends that its

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1 National Grid USA also owns affiliated electric and gas distribution companies operating in Rhode Island and New York, while National Grid plc owns and operates electricity transmission, gas transmission and distribution networks in the United Kingdom (Exh. NG-MLR-1, at 23).

2 On September 12, 2016, the Company advised the Department of the need to file amended Annual Returns for calendar years 2014 and 2015 to correct a purported error

petition also includes a $68.7 million decrease in revenues recovered in charges outside of base rates (Exh. NG-RRP-2, at 1 (Rev. 3)). Thus, the Company claims that its petition requests a net increase in annual delivery revenues of $133.2 million, or an approximately 20.3 percent increase in current annual delivery revenues (Exh. NG-RRP-2, at 1 (Rev. 3)).

As part of this filing, National Grid also seeks to continue, with several proposed modifications, its capital investment recovery mechanism ("CapEx"), which was approved in D.P.U. 09-39 and permits the Company to recover the revenue requirement associated with incremental capital investments. Further, National Grid seeks to continue, with several proposed modifications, its storm contingency fund, which originally was approved in New England Electric System, D.T.E. 99-47 (2000) and permits the Company to recover costs associated with certain storm-restoration activities. In addition, the Company offers several rate design-related proposals and a tariff intended to recover incremental property tax expense. The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015 (Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).

II. PROCEDURAL HISTORY

On November 16, 2015, the Attorney General of the Commonwealth of Massachusetts filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). On December 1, 2015, the

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regarding the recording of plant in service for fiscal years ending March 31, 2013 through 2016 (Cover Letter at 1, dated September 12, 2016). According to National Grid, now that the costs are correctly recorded, the Company will experience a net increase to operating expense of approximately $200,000 annually that will not be reflected in new distribution rates set in this proceeding (Cover Letter at 1). The Company does not seek to incorporate into the record in the instant case these amended Annual Returns, or the corrected recording of plant and expenses (Cover Letter at 1). Nevertheless, the Department finds that the Company's filing is extra-record material to which we give no probative weight. The Department will not consider these materials in evaluating the Company's instant petition for a base rate increase.

Department granted full party status to the Department of Energy Resources ("DOER") and the Low-Income Weatherization and Fuel Assistance Program Network ("Low Income Network"), limited participant status to PowerOptions, Inc., and joint limited participant status to NSTAR Electric Company, NSTAR Gas Company and Western Massachusetts Electric Company, together doing business as Eversource Energy. On December 10, 2015, the Department granted limited participant status to Solar Energy Industries Association. The following day, the Department granted limited participant status separately to The Berkshire Gas Company, and jointly to The Energy Consortium ("TEC") and Associated Industries of Massachusetts ("AIM"). On December 14, 2015, the Department granted limited participant status to The Alliance for Solar Choice. On December 17, 2015, the Department granted limited participant status to Brightergy, LLC.

On January 14, 2016, the Department granted limited intervenor status to Acadia Center; Vote Solar; Direct Energy Business, LLC, Direct Energy Services, LLC, and Astrum Solar, Inc. d/b/a Direct Energy Solar (collectively as "Direct Solar"); Energy Freedom Coalition of America, LLC ("EFCA"); and Northeast Clean Energy Council, Inc. ("NECEC"). <u>See</u> <u>Massachusetts Electric Company and Nantucket Electric Company</u>, D.P.U. 15-155, Interlocutory Order (January 14, 2016).

Pursuant to notice duly issued, the Department held five public hearings in the Company's service territory: (1) in Brockton on March 15, 2016; (2) in Nantucket on March 21, 2016; (3) in Worcester on March 30, 2016; (4) in Great Barrington on April 4, 2016; and (5) in Lawrence on April 6, 2016. The Department also received written comments from public officials and several National Grid ratepayers.

The Department held 15 days of evidentiary hearings from May 2, 2016, through May 26, 2016. In support of the Company's filing, the following witnesses, all of whom are employed by National Grid USA Service Company, Inc. ("NGSC"), provided testimony: (1) Marcy L. Reed, president – Massachusetts; (2) Michael D. Laflamme, vice president, regulation and pricing – New England; (3) Margaret H. Kinsman, director of revenue requirements group – New England; (4) Maureen P. Heaphy, vice president of compensation, benefits and pensions; (5) James H. Patterson, Jr., director of network strategy – New England; (6) Stefan Nagy, analyst, program strategy; (7) John E. Walter, principal engineer, outdoor lighting and attachments group; (8) Jeanne A. Lloyd, principal program manager (electric pricing), regulation and pricing group – New England; (9) Peter T. Zschokke, director, regulatory strategy; (10) Scott M. McCabe, manager (electric pricing), regulation and pricing group – New England; (11) Timothy Roughan, director, energy/environmental policy; (12) Daniel J. DeMauro, Jr., director, IS Regulatory Compliance; (13) David H. Campbell, vice president, corporate finance; (14) Christopher P. Murphy, acting vice president, chief information officer; (15) Ryan Moe, senior specialist for vegetation strategy; (16) Daniel Bunszell, vice president, electric operations – New England; (17) Gladys Sarji, customer satisfaction and regulatory compliance; (18) Nancy Concemi, director, New England call center; and (19) John B. Currie, director, revenue and regulation – New England. In addition to NGSC personnel, the following outside consultants provided testimony on behalf of National Grid: (1) Robert B. Hevert, managing partner, Sussex Economic Advisors; (2) Ronald E. White, president, Foster Associates Consultants, LLC; (3) Howard Gorman, president, HSG Group, Inc.; and (4) Wayne S. Watkins, Pro Unlimited, Inc.

The Attorney General sponsored the testimony of the following witnesses:[3] (1) J. Randall Woolridge, Ph.D., professor of finance, Pennsylvania State University; (2) David J. Effron, consultant, Berkshire Consulting Services; (3) Donna Ramas, principal, Ramas Regulatory Consulting, LLC; (4) Timothy Newhard, analyst, Attorney General's Office of Ratepayer Advocacy; (5) Kyle Connors, analyst, Attorney General's Office of Ratepayer Advocacy; (6) Daniel O'Neill, president, O'Neill Management Consulting; (7) Charles Fijnvandraat, principal, Fijnvandraat Consulting Group; (8) Scott Rubin, consultant; and (9) William Dunkel, principal, William Dunkel and Associates.

The Low Income Network sponsored the testimony of John G. Howat, senior policy analyst, National Consumer Law Center, and Marina Levy, research assistant, National Consumer Law Center. Acadia Center sponsored the testimony of Abigail Anthony, Ph.D., director, grid modernization and utility reform, Acadia Center. Direct Energy sponsored the testimony of Frank Lacey, principal, Electric Advisors Consulting. EFCA sponsored the testimony of Tim Woolf, vice president, Synapse Energy Economics, Inc., and Melissa Whited, senior associate, Synapse Energy Economics, Inc. NECEC sponsored the testimony of R. Thomas Beach, principal consultant, Crossborder Energy. Finally, Vote Solar sponsored the testimony of Nathan Phelps, program manager, distributed generation regulatory policy, Vote Solar.

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3 On December 15, 2015, the Department approved the Attorney General's retention of experts and consultants at a cost of $250,000, pursuant to G.L. c. 12, § 11E(b). See D.P.U. 15-155, Order on Attorney General Retention of Experts and Consultants (2015).

On June 17, 2016, the Department received initial briefs/comments from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, NSTAR Electric Company and Western Massachusetts Electric Company (collectively as "Eversource") and Vote Solar. National Grid submitted its initial brief on July 1, 2016.

On July 18, 2016, the Department received reply briefs from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, Vote Solar, PowerOptions, Inc., and, collectively, from TEC and AIM. The Company submitted its reply brief on July 25, 2016. The evidentiary record consists of more than 3800 exhibits and responses to 97 record requests.

III. NATIONAL GRID'S USE OF A SPLIT TEST YEAR

A. Introduction

The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015, a non-calendar or "split" test year (see Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).[4] Non-calendar test years have, on occasion, been accepted by the Department – most recently for water companies. See, e.g., Plymouth Water Company, D.P.U. 14-120, at 16 (2015); Milford Water Company, D.P.U. 12-86, at 1 (2013); Colonial Water Company, D.P.U. 11-20 (2011); Massachusetts-American Water Company, D.T.E. 00-105 (2001). As discussed in further detail below, the Department recently expressed its strong preference for a calendar year test year and noted that any company that seeks to rely on a split test year faces a

4 A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. NSTAR Gas Company, D.P.U. 14-150, at 45, n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar test year or a split test year, comprises a period of twelve consecutive calendar months.

high burden to demonstrate as a threshold matter that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16 & n.11.

In support of its split test year filing, National Grid retained the independent accounting firm of PricewaterhouseCoopers, LLC ("PwC") to review the Company's operations and verify the accuracy of its non-calendar year test year financial data (Exhs. NG-RRP-1, at 6-7; NG-RRP-3).[5] PwC's review was performed under the attestation standards of the American Institute of Certified Public Accountants (Exh. NG-RRP-3, at 4). On October 30, 2015, PwC issued a report ("PwC Report") of its findings, which the Company submitted as part of the initial filing in this case (Exh. NG-RRP-3).

The scope of PwC's examination encompassed transactions recorded by the Company and NGSC (Exh. NG-RRP-3, at 4). PwC reviewed selected transactions that occurred during the test year in order to form an opinion on the accuracy of those transactions (Exh. NG-RRP-3, at 4). The transactions reviewed included vendor costs, labor costs and employee expense costs (Exh. NG-RRP-3, at 5).[6] PwC also examined general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 5). The PwC Report describes the sampling method used for each cost area (Exh. NG-RRP-3, at 5). The PwC Report also

[5] The Company does not seek inclusion of the costs incurred for this review in this proceeding (Exhs. DPU-4-9; DPU-4-10; AG-15-1, at 2 (corrected)).

[6] For example, PWC performed the following tests with respect to vendor costs: (1) compare the cost recorded in the Company's ledger to the underlying vendor support such as an invoice or similar document; (2) review the underlying vendor information for the details of the services performed and identify whether services relate to the entity to which they were charged; and (3) review the underlying vendor information for the details of the services performed and identify whether the services were performed in support of the capital program (Exh. NG-RRP-3, at 6).

describes the testing procedures performed to ensure that costs were incurred, accurately calculated to reflect the underlying transaction, allocated to the correct operating company (where applicable), properly allocated among capital and expense (where applicable), and consistent with Company policy (Exh. NG-RRP-3, at 6). PwC examined, on a test basis, evidence supporting management's assertions regarding costs and performed other such procedures as PwC considered necessary under the circumstances (Exh. NG-RRP-3, at 27, 46). PwC concluded that the selected costs, in all material respects, were accurate (Exh. NG-RRP-3, at 27, 46).

B. Positions of the Parties

1. Attorney General

The Attorney General submits that because the Department establishes a utility's cost of service using test year data, and that the resulting distribution rates may be in effect for five years or more, a utility's test year financial information must be "accurate, verifiable, and verified" (Attorney General Brief at 8). Further, the Attorney General contends that the use of a spilt test year, rather than a calendar year, is problematic because it does not conform to the annual reporting periods or requirements set forth by the Department, the Federal Energy Regulatory Commission ("FERC"), and the Securities and Exchange Commission (Attorney General Brief at 8). She asserts that in the instant case, because National Grid chose to file its base rate case using a split test year, the Company must comply with the directives set forth in D.P.U. 14-120 to ensure that the record contains reliable and verifiable financial information (Attorney General Brief at 9-10).

In this regard, the Attorney General argues that National Grid failed to comply with the split test year filing requirements set forth in D.P.U. 14-120, because the Company: (1) failed to show that its test year account balances tie back to its Annual Returns to the Department;[7] and (2) failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9).[8] With respect to the first point, the Attorney General contends that the Company's requested rate increase is based on unverified worksheets (Attorney General Brief at 9). Further, the Attorney General claims that the PwC Report does not support the notion that the Company's account balances tie back to the Annual Return (Attorney General Reply Brief at 5). The Attorney General asserts that because a calendar year test year ties back to a company's Annual Return, the same level of verification is required for a split test year filing (Attorney General Reply Brief at 5). According to the Attorney General, the Department cannot on its own verify the accuracy of the Company's test year data and instead an

7 Electric distribution companies, such as National Grid, must file an Annual Return with the Department annually on or before March 31. G.L. c. 164, § 83; 220 C.M.R. § 79.00, Introduction. The Annual Return includes the FERC Form 1 prescribed by FERC. 220 C.M.R. § 79.04(1). The FERC Form 1 presents financial and other operating data based on a calendar year ending December 31. 18 C.F.R. § 141.1(b)(2). The use of a calendar test year ensures that test year amounts tie back to the amounts included in the Annual Returns, and offers a level of assurance that the amounts have been properly recorded and are generally available for review. D.P.U. 14-120, at 11.

8 As explained by the American Institute of Certified Public Accountants ("AICPA"), an unqualified opinion presented in a report on the audit of financial statements states that the financial statements present fairly, in all material respects, the financial position, results of operations, and cash flows of the entity in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508.10, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf.

unqualified opinion letter is necessary for such verification (Attorney General Reply Brief at 3, 5, citing D.P.U. 14-120 at 11 & 16, n.11).

With respect to the audit requirement, the Attorney General argues that the Company's financial records were simply reviewed by an independent third party (i.e., PwC) and not audited as required by the Department in D.P.U. 14-120 (Attorney General Brief at 9, n.5, citing Exh. NG-RRP-1, at 6). In this regard, the Attorney General argues that PwC's review and subsequent report does not equate to an unqualified opinion letter from an independent auditor attesting to the accuracy of the financial information used to develop the cost of service in this case (Attorney General Brief at 9; Attorney General Reply Brief at 5). Further, the Attorney General rejects any notion that PwC's review of the Company's financial information was more thorough than a financial audit (Attorney General Reply Brief at 5). Thus, the Attorney General asserts that the Company has failed to meet its burden to provide an adequate record sufficient to enable the Department to conduct a meaningful review (Attorney General Reply Brief at 3, citing Town of Hingham v. Dep't. of Telecom. and Energy, 433 Mass. 198, 213-214 (2001)).[9]

Based on the above considerations, the Attorney General asserts that the Department should consider as a factor in setting National Grid's allowed rate of return, the Company's

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9 In particular, the Attorney General identifies three areas where she argues that a financial audit could have prevented the submission of inaccurate data to the Department: (1) the Company's purported overstatement of its depreciation expense caused by the inclusion of $100 million in plant retirements in the test year-end plant balance; (2) the Company's purported overstatement of net plant due to the failure to record $26 million in salvage; and (3) the Company's purported omission of certain project reports relating to plant additions (Attorney General Reply Brief at 4, citing Exhs. AG-18-19; AG-30-1, Att.; RR-AG-28). These issues are discussed in Sections III and VIII.E below. According to the Attorney General, a proper audit likely would have revealed additional significant inaccuracies that would be highly relevant to this proceeding (Attorney General Reply Brief at 4).

failure to meet the directives of D.P.U. 14-120 in using a split test year. Specifically, the Attorney General recommends that the Department should set the Company's allowed return on equity ("ROE") at the lowest end of the range of reasonableness (Attorney General Brief at 10, citing Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 231 (2002); Attorney General Reply Brief at 6).

2. Company

National Grid argues that it prepared its filing in compliance with the directives set forth in D.P.U. 14-120 (Company Brief at 9, citing Exh. NG-RRP-1, at 6-7). First, the Company argues that it developed financial statements that directly tie to the Company's 2014 Annual Return and to data submitted to FERC on FERC Forms 1 and 3-Q,[10] which are signed and sworn to by an officer of the Company (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). More specifically, the Company argues that these financial statements incorporate data submitted to FERC on FERC Form 1 for the calendar year 2014, which comprise the first six months of the test year, and FERC Form 3-Q for the year to date periods ending June 30, 2014 and June 30, 2015 (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). The Company contends that these financial statements provide the Department with a direct tie to data included in the Company's 2014 Annual Return and allow for a meaningful year-to-year comparison of twelve months of data to the annual data provided in the Annual Returns (Company Brief at 9,

[10] FERC Form 3-Q presents financial and operating data on a calendar quarter basis, with a FERC Form 3-Q filed for each calendar quarter. 18 C.F.R. § 260.300. The Department does not require companies to submit their FERC Form 3-Q.

citing Exh. NG-RRP-1, at 6-7). The Company asserts that the Attorney General has not raised any specific instances of how these financial statements fail to tie back to the 2014 Annual Return, FERC Form 1 or FERC Form 3-Q (Company Brief at 14).

Second, National Grid argues that the PwC Report provides a solid foundation for the Department to review and analyze the Company's financial records used to develop the cost of service because it is an extensive third-party review of the test year data designed to verify data integrity and accuracy (Company Brief at 9, 15, citing Exhs. NG-RRP-1, at 6-11; NG-RRP-3). According to National Grid, there is no requirement set forth in D.P.U. 14-120 that the test year data is to be included in a routine annual audit or that the Company needs to obtain an unqualified opinion (Company Reply Brief at 13). Instead, the Company argues that D.P.U. 14-120 requires a showing that the test year amounts have been "properly audited," and that the PwC Report is sufficient to meet that requirement (Company Reply Brief at 13). In this regard, the Company asserts that PwC's review: (1) was performed under appropriate industry standards; and (2) was more thorough than the Company's annual financial audit conducted by PwC, particularly in relation to the specific financial data forming the cost of service in this proceeding (Company Brief at 10-11, 15, citing Exhs. NG-RRP-1, at 6-7; NG-RRP-3, at 4-5; AG-15-1, at 8, 9 (Corrected); Tr. 9, at 1399-1400, 1522-1523; Company Reply Brief at 13).

According to the Company, the PwC Report shows that: (1) the costs charged to the operating companies from the service companies were recorded accurately; (2) on a net basis, the costs were allocated appropriately to the various operating companies, consistent with the appropriate cost allocation manual; (3) the findings associated with the cost data provided in the scope of testing were not material to the service companies involved or to any one business unit;

and (4) there were no other pertinent facts identified during the review process indicating that the cost should be allocated differently (Company Brief at 12, citing Exhs. NG-RRP-3; AG-15-2, at 10 (Supp.)). The Company asserts that there is no evidence to suggest that a different type of audit would have produced different results (Company Reply Brief at 13-14).

Based on the foregoing, National Grid argues that the PwC Report substantiates the Company's use of a split test year in this proceeding and meets the threshold requirements set forth by the Department in D.P.U. 14-120 (Company Brief at 13). Thus, the Company asserts that the Department should find that the Company has met its burden with respect to using a split test year, and it should reject the Attorney General's recommendation that an adjustment to the allowed rate of return is warranted (Company Brief at 13, 16; Company Reply Brief at 15-16).

C. Analysis and Findings

1. Introduction

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45; D.P.U. 14-120, at 12, 16; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); 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). See also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to G.L. c. 164, § 94 ("§ 94"), the Department examines a test year on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

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

As noted above, the Department has expressed strong preference for a test year cost of service based on a calendar year as opposed to a split test year. D.P.U. 14-120, at 12, 16; see also D.P.U. 14-150, at 45, n.26. Although the Department has, on occasion, accepted a non-calendar test year, see D.P.U. 14-120, at 10, 16; D.P.U. 12-86, at 1; D.P.U. 11-20; D.T.E. 00-105, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; see AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test year amounts associated with a split test year will not tie back to amounts included in the Annual Returns submitted to the Department, which are prepared on a calendar-year basis. D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test year may create an improper incentive for utilities to book expenses into a certain time period for purposes of creating an inflated test year expense. D.P.U. 14-120, at 11. Another complication associated with use of split test years involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate setting process, may result in distorted measurement of net operations. D.P.U. 14-120, at 11; see The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

It also is well established that the burden is with a company to satisfy the Department that the company's proposal will result in just and reasonable rates. D.P.U. 14-120, at 11-12; Boston Gas Company, D.T.E. 03-40, at 52, n.31 (2003), citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993); Blackstone Gas Company, D.P.U. 19579, at 2-3 (1978).[11] Therefore, given the importance of the concerns discussed above and their significance for ratepayers, the Department affirms its very clear preference to use an historic calendar year test year to establish rates. D.P.U. 14-120, at 11-12.

As we noted in D.P.U. 14-120, at 12, any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and

11 That the burden of proof is always with those who take the affirmative in pleading is a long-held tenet in Massachusetts jurisprudence. Phelps v. Hartwell, 1 Mass. 71, 73 (1804).

reasonable. Specifically, any company that seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976). Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

> (1) of how its test year account balances tie back to the account balances as reported in the Annual Returns;
>
> (2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;
>
> (3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and
>
> (4) that the company has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances.

D.P.U. 14-120, at 16 n.11.

2. Discussion

As noted above, the Attorney General's challenge to the propriety of National Grid's reliance on a split test year rests on two main arguments: (1) that the Company failed to show that its test year account balances tie back to the Annual Return to the Department; and (2) that the Company failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9). However, we will address all four split test year threshold requirements set forth in D.P.U. 14-120.

First, the Company provided audited financial statements for the fiscal year ending March 31, 2015 (Exh AG-1-2, Att. 3 (3g) & (4g)).[12] While the Company's audited financial statements are not prepared using the same twelve-month period as the test year, the Department finds such statements helpful in ensuring that the Company's test year account balances have been verified, especially given that nine of the twelve months were the subject of the audit of the fiscal year ended March 31, 2015 (Exh. AG-1-2, Att. 3 (3g), (4g); Tr. 9, at 1397). The Company also provided the FERC Form 1s for the calendar years ending December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 4 (1f), (2f); RR-AG-29, Atts. 1, 3). Further, the Company provided its Annual Returns to the Department for calendar years ended December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 7 (1f), (2f); RR-AG-29, Atts. 2, 4). In addition, the Company provided FERC Form 1 financial statements containing financial information for the twelve months ended June 30, 2015 (Exhs. NG-RRP-1 at 6; WP-NG-RRP-1(a), (b), (c)). Based on our review of this information, we find that it is possible, though not easily discernible, to tie the Company's test year account balances back to the account balances as reported in the Annual Returns. See D.P.U. 14-120, at 16 n.11.

Next, the Company provided audited financial statements for the fiscal years ended 2009 through 2014 (Exh. AG-1-2, Atts. 3 (3a) through (4g)). In addition, the Company provided the

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12 A financial audit is an examination of historical financial statements performed in accordance with generally accepted auditing standards, with a report issued on the results stating an opinion whether the financial statements present the audited entity's financial position, results of operations, and cash flows in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508, n.1, §§ 508.07.08, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf; see also D.P.U. 14-120, at 15.

FERC Form 1s for calendar years ending December 31, 2009 and December 31, 2013 (Exh. AG-1-2, Atts. 4 (1a) through (2f)). We conclude that this information, when reviewed in conjunction with the test year data and the PwC Report (as discussed in greater detail below), allows for a meaningful review of year-to-year changes in expense levels in order to determine whether the Company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability. See D.P.U. 14-120, at 16 n.11.

Further, we find that the test year amounts have been properly audited and are available for review. In particular, we are not persuaded by the Attorney General's argument that the Company's financial statements are unreliable because they lack verification through an unqualified opinion letter. While the PwC Report does not represent an unqualified opinion letter, we find that it does provide an independent and extensive review of the Company's test year cost of service data that is sufficient to make the D.P.U. 14-120 threshold showing. As noted, the record contains several of the Company's annual financial audits (Exh. AG-1-2, Att. 3 (3g) & (4g); Tr. 9 at 1397). As discussed below, in this instance PwC's review was, in a number of ways, likely more extensive than the scope of these financial audits.

The record shows that PwC performed an extensive review of over 4,500 individual invoice transactions relevant to the Company's cost of service in this case, including vendor costs, labor costs, employee expense costs, and general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 4-5; Tr. 9, at 1522-1523). Thus, PwC's review encompassed a wide range of expense activity on a transactional level, as opposed to a review of a smaller sample population of transactions, which is typically done in a financial audit (Exh. NG-RRP-1, at 8-9; Tr. 9, at 1399-1400).

For each cost area, the PwC Report clearly describes the methods used to select which transactions were reviewed (Exh. NG-RRP-3, at 5). Further, the PwC Report describes the extensive testing procedures performed to verify the propriety of costs incurred by the Company in the split test year (Exhs. NG-RRP-3, at 6; NG-RRP-1, at 7-8). The record shows that for each of the charges it reviewed, PwC examined relevant supporting documentation, such as invoices, expense reports, receipts, time sheets and other documents (Exhs. NG-RRP-3, at 6; AG-15-1, at 8 (corrected)). Further, for each charge, PwC confirmed that it was: (1) incurred during the split test year; (2) accurate; (3) properly allocated to the correct company or companies (where applicable) and to expense or capital (where applicable); (4) properly allocated in accordance with National Grid USA's Cost Allocation Policies and Procedures Manual ("CAM"); and (5) not accounted for as below-the-line for ratemaking purposes (Exhs. NG-RRP-1, at 7-8; NG-RRP-3, at 6, 30; AG-15-1, at 8 (corrected)). Thus, PwC's review was likely more extensive for ratemaking purposes than a financial audit, which tends to focus on whether the Company has properly maintained its financial records consistent with accounting requirements. See D.P.U. 14-120, at 15. If PwC found that there was inadequate support for a particular charge or if it had questions regarding a particular charge, it undertook a further examination of the charge, including requesting additional documentation to support the charge and, frequently, following up with the business process owner to understand the allocation related to a particular charge (Exh. NG-RRP-1, at 8). In instances where the Company could not provide sufficient support for the charge or a clear explanation of the charge allocation, PwC flagged the charge as a proposed adjustment or considered whether a different bill pool or direct charge would have been more appropriate to use as a basis for cost allocation (Exh. NG-RRP-1, at 8). Based on the quality and comprehensiveness of PwC's review, we find that there is a sufficient basis to conclude that the Company's test year amounts have been properly "audited" in order to satisfy the split test year threshold requirement as set forth in D.P.U. 14-120. D.P.U. 14-120, at 16 n.11.[13]

Finally, PwC reviewed beginning and end-of-year accruals in order to review the allocation of costs among monthly periods during the split test year (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). In particular, PwC identified all vendor cost invoices that had service dates prior to the beginning of the test year and compared the amount recognized as a cost in the test year to the amount accrued at the beginning of the test year and reversed during the test year, in order to test the elimination of out-of-period charges in the test year data (Exh. NG-RRP-3, at 14, 24). PwC then reviewed accruals recorded at the end of the test year and compared the amounts of supporting calculations (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). Further, PwC reviewed a number of invoices received after the test year to determine if those invoices related to services performed in the test year and, for those invoices that did, compared the

13 In light of this finding, we need not address the Attorney General's argument that the Department cannot, on its own, verify the Company's test year data. Further, we are not persuaded by the Attorney General's argument that use of a calendar year test year and an unqualified opinion letter would have prevented the Company's purported overstatement of depreciation and net plant, or its alleged failure to file certain project reports at the outset of the case (Attorney General Reply Brief at 4). While we expect National Grid to present a filing that is as complete and accurate as possible, these concerns are not sufficient to call into question the reviewability of the Company's entire rate request. Instead, the Department will determine the appropriate ratemaking treatment of these items, under the circumstances identified by the Attorney General, in the relevant sections of this Order.

invoice to the accruals at the end of the test year to determine an appropriate adjustment to test year costs (Exh. NG-RRP-1, at 9).[14] Based on these findings, we conclude that through the PwC Report, the Company has shown that it has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances. D.P.U. 14-120, at 16 n.11.

3. Conclusion

Based on the above considerations, the Department finds that National Grid has satisfied the split test year threshold requirements set forth in D.P.U. 14-120 and has demonstrated by clear and convincing evidence that its financial data is reviewable and reliable and represents a full accounting of the Company's operations for the test year period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate National Grid's filing based on a test year for the twelve months ending June 30, 2015. Further, we decline to make any specific adjustment to the Company's ROE due to the use of a split test year, as recommended by the Attorney General. However, while we accept PwC's findings for purposes of determining the accuracy and reviewability of the financial information submitted by the Company in this case, we do not accept the PwC Report as a proxy for establishing the appropriate cost of service in this case. As we have noted in prior cases, while audited financial statements are of considerable assistance in the ratemaking process, an audit does not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded

[14] For this aspect of its examination and verification process, PwC reported a net decrease to test year costs for the Company in the amount of $1,094,601 (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 7, 24). The Company states that this amount was offset by findings in other elements of PwC's review (Exh. NG-RRP-1, at 9).

to such costs. D.P.U. 14-120, at 15; citing Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240, Introductory Letter (May 19, 1941); Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997). The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

Finally, we emphasis that our findings here are limited to the specific facts and circumstances of this case and in no way change the Department's clear preference for companies to use a calendar year test year as the norm. D.P.U. 14-120, at 16. We reiterate that any company that seeks to rely on a split test year must, at a minimum threshold level, make a prima facie showing by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Failure to make such a robust showing will result in dismissal of the company's rate proceeding.

IV. REVENUE DECOUPLING MECHANISM

A. Introduction

In D.P.U. 07-50-A at 4-5, 32, 81-82, the Department directed each electric and gas distribution company to propose a full revenue decoupling mechanism ("RDM") in its future base distribution rate proceedings. The Department stated that the objective of revenue decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring 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.

In directing electric distribution companies to adopt full revenue decoupling, the Department acknowledged that decoupling would remove the opportunity to earn additional revenue from growth in sales between base distribution rate proceedings and further acknowledged that such revenue typically funded, among other things, increased operation and maintenance ("O&M") expenses as well as system reliability and capital investment projects. D.P.U. 07-50-A at 48, 87. Accordingly, the Department stated that it would consider company-specific proposals that account for the effects of increased capital investments and inflation on target revenue. D.P.U. 07-50-A at 49-50.[15]

The Department approved the Company's revenue decoupling provision in its last base distribution rate proceeding. D.P.U. 09-39, at 61-92. National Grid's current revenue decoupling tariff provision includes two components that operate in concert: (1) a traditional RDM reconciliation with full revenue decoupling; and (2) the Company's CapEx mechanism (Exh. NG-PP-1, at 82-83). In the RDM reconciliation, the annual target revenue ("ATR") set in the Company's base distribution rate proceeding is adjusted by the cumulative CapEx cost recovery for the upcoming year (Exh. NG-PP-1, at 83). The adjusted ATR is reconciled against billed base distribution revenue and CapEx factor revenue (Exh. NG-PP-1, at 83). The Company is authorized to collect up to three percent of total revenues through the resulting revenue decoupling adjustment factors ("RDAFs") (Exh. DPU-18-21, Att. at 5 (M.D.P.U. No. 1289,

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15 See Section VII.B for a discussion of the Company's proposal regarding capital investments.

Sheet 4, § V)). Each year's ATR is greater than the prior year's ATR because the CapEx cost recovery cumulates year-over-year from additional capital investments (Exh. NG-PP-1, at 83). Additionally, the total amount that the Company seeks recovery of through the RDM will eventually reach and exceed the three-percent cap because National Grid measures the entire annual CapEx cost recovery against the three-percent cap, instead of the change in CapEx cost recovery from year-to-year (Exh. NG-PP-1, at 85-86). Moreover, the current revenue decoupling provision does not permit the Company to apply a revenue cap separately to its RDM reconciliation component and to its CapEx recovery component (Exh. NG-PP-1, at 85). Instead, the three-percent cap is compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86).

B. Company Proposal

The Company proposes to remove the CapEx cost recovery from the current revenue decoupling provision tariff and move this component to a separate tariff and operate it as an independent cost recovery mechanism (see Section V) (Exhs. NG-PP-1, at 81; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).[16] The Company proposes that the remaining components of the revenue decoupling provision will govern the operation of National Grid's traditional RDM reconciliation.

In particular, the Company proposes to continue the traditional RDM reconciliation component in its revenue decoupling provision, with updated target revenues set at the proposed base rate revenue requirement for each customer class and modifications to the revenue cap

16 The Company proposes to apply a separate revenue cap to the independent CapEx recovery component (Exhs. NG-PP-1, at 81-82; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).

(Exhs. NG-PP-1, at 81; NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). National Grid's current and proposed ATRs by rate class are shown in the following table:

Rate Class	**Current ATR**	**Proposed ATR**
Rate R-1/R-2	$306,532,557	$451,769,965
Rate R-4	$347,350	$599,269
Rate G-1	$97,267,709	$97,070,193
Rate G-2	$56,298,775	$91,441,732
Rate G-3	$106,895,246	$140,607,030
Street lighting	$20,525,360	$17,639,752
Total	$587,866,996	$799,127,941

(Exhs. NG-PP-23, at 181 (proposed M.D.P.U. No. 1278, at sheet 2); NG-PP-24, at 259; DPU-18-21, Att. at 4). National Grid proposes to submit annual RDM filings by January 15 to reconcile its actual revenues to the ATR pursuant to its revenue decoupling provision, with the RDAFs to take effect on March 1 (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

However, the Company proposes two modifications to the RDM cap: (1) the revenue that forms the basis for the RDM cap will reflect total revenue and include an adjustment for electric supply for those customers who took service from a competitive supplier during the year; and (2) a three-percent cap will be applied to both under- and over-recoveries of the RDM reconciliation between billed revenue and ATR (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23).

Finally, in the Company's 2015 annual RDM reconciliation filing, the Department directed National Grid to adjust its ATR, not its distribution revenues, to account for the sale of street lighting assets, and the Company amended its revenue decoupling provision tariff accordingly (see Exh. DPU-18-21, Att. (M.D.P.U. No. 1289)). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136-A at 11 (January 21, 2016). The primary revision to the revenue decoupling provision tariff was the addition of the "Streetlight Sales Adjustment" definition (Exh. DPU-18-21, Att. at 3 (M.D.P.U. No. 1289, at sheet 2)).[17]

C. Positions of the Parties

National Grid argues that the proposed modifications to its revenue decoupling provision align it with the operation of RDMs in place for other distribution utilities (Company Brief at 164).[18] No other party addressed the Company's proposed modifications to the traditional RDM reconciliation on brief.

D. Analysis and Findings

In Section V.D below, the Department allowed the Company to continue the operation of its CapEx mechanism in a separate tariff, with modifications, including its separation from the revenue decoupling provision and operation as a distinct reconciling mechanism. Thus, in this section we will address the Company's remaining proposed revisions to its traditional RDM reconciliation component of its current revenue decoupling provision.

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17 According to the Company, "'Streetlight Sales Adjustment' shall mean the annual cumulative dollar adjustment to each year's ATR as a result of selling its streetlighting equipment pursuant to G.L. c. 164 § 34A subsequent to the effective date of new base distribution rates resulting from a general rate case. The Streetlight Sales Adjustment shall be a downward adjustment to each year's ATR and shall be calculated as the proceeds received by the Company from the sale of its streetlighting equipment multiplied by the avoided cost of no longer owning, operating, and maintaining such equipment, stated as a percentage, as determined by the Company's final streetlight revenue requirement. The Streetlight Sales Adjustment shall be set to zero and calculated for new streetlight sales effective with the subsequent implementation of new base distribution rates as provided for above. The Streetlight Sales Adjustment is pursuant to the Department's directive in D.P.U. 14-136-A" (Exh. DPU-18-21, Att. at 3).

18 The Company does not specify whether these utilities are gas or electric utilities (Exh. NG-PP-1, at 84). However, the Company states that gas utility targeted infrastructure replacement programs demonstrate similar language on the application of revenue caps (Exh. NG-PP-1, at 84).

The Department has determined that a RDM must be consistent with our precedent related to rate continuity, fairness, and earnings stability. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50, at 12 (2007). The Department has found that the application of a revenue cap in the context of a RDM is consistent with this precedent. D.P.U. 14-150, at 20; Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 116 (2011). Moreover, the Department has previously stated that revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates. Western Massachusetts Electric Company, D.P.U. 10-70, at 45 (2011); D.P.U. 09-39, at 87.

The Company proposes two modifications to the RDM cap. First, the Department evaluates the Company's proposal to include an adjustment for electric supply for those customers who took service from a competitive supplier during the year. We find that this proposed adjustment is consistent with decoupling mechanisms in use by other utilities. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 24. Therefore, the Department accepts the Company's proposal.

Next, we address the proposed three-percent cap to be applied to the RDM reconciliation between billed revenue and ATR. The Company proposes to cap the total RDM reconciliation (excluding CapEx cost recovery) at three-percent of total revenues, including an adjustment for electric supply for those customers who took service from a competitive supplier during the year, and to apply the three-percent cap to both under- and over-recoveries of the RDM reconciliation balance (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23). In previously approving a three-percent cap in the Company's revenue decoupling provision (which included CapEx cost recovery), the Department stated that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render the three-percent cap inappropriate. D.P.U. 09-39, at 88. The Department expressed that it may review and modify such a cap, as necessary, over the course of the Company's revenue decoupling adjustment filings. D.P.U. 09-39, at 88.

Although the Company's three-percent cap is consistent with the revenue decoupling provision approved in its previous base distribution rate proceeding, the three-percent cap was applied to an RDM adjustment that previously included a RDM reconciliation balance with an adjustment for CapEx cost recovery. D.P.U. 09-39, at 87-88. The three-percent cap was compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86). However, given that we have approved the continuation of the CapEx mechanism as a separate mechanism from the revenue decoupling tariff provision (see Section V.D below), it is now more appropriate to set National Grid's cap on the annual revenue decoupling adjustment at one-percent cap of total revenue. We conclude that a one-percent cap based on total revenues ensures continuity, fairness, and earnings stability. Any amount above the one-percent cap will be deferred with interest calculated at the customer deposit rate until there is sufficient room under a future cap to recover the deferral balance (Exhs. NG-PP-1, at 84; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

Additionally, the purpose of the one-percent cap is to protect customers from large revenue decoupling adjustments. D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. However, no such protection is necessary in the event of a decoupling adjustment credit.

D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. Accordingly, the Department declines to accept the Company's proposal to apply the revenue cap to over-recoveries of ATR, which would result in a credit to customers (see Exh. DPU-18-23). The Department finds that the one-percent revenue cap shall apply only to under-recoveries of ATR.

Based on the foregoing, the Department directs the Company to modify the language of its revenue decoupling provision tariff to include a revenue decoupling adjustment cap that is based on one-percent of total Company revenues from the previous calendar year. National Grid is also directed to include language in its revenue decoupling provision tariff that ensures that the revenue decoupling adjustment cap is applied only to under-recoveries to be collected from ratepayers in the RDAFs.

With respect to the ATRs proposed in this filing, we note that they are calculated from the revenue requirements proposed by the Company to be collected from each rate class (Exhs. NG-RRP-2, at 1 (Rev. 1); NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). As noted below in Schedule 1, the Department has approved a different revenue requirement than that proposed by the Company. As such, the Company is directed, in its compliance filing, to file new ATRs by rate class based on the revenue requirement for each rate class approved in this Order.

Further, in D.P.U. 14-136-A, the Department directed the Company to adjust its ATRs to account for the sale of street lighting assets. D.P.U. 14-136-A at 11. The Company added a definition to its revenue decoupling provision for "Streetlight Sales Adjustment" (see n.17 above) in compliance with that Order (Exh. DPU-18-21, Att. at 8). The Department directs the

Company in its compliance filing to include these tariff modifications, as approved in D.P.U. 14-136-A, in its revenue decoupling provision tariff.

Finally, the Department reiterates that the RDM allows companies to modify, on an annual basis, base distribution rates as a result of changes in sales in order to promote the efficient deployment of demand resources. D.P.U. 09-39, at 9, 62-63. Revenue decoupling was intended to provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future. D.P.U. 07-50-A at 1. Moreover, the Department noted that the conclusions reached in D.P.U. 07-50-A represented general statements of policy. D.P.U. 14-150, at 16-17; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-B, at 28-29 (2008).

The Department acknowledges that we have our own concerns about the appropriateness of including street lighting rate classes in a revenue decoupling provision. Currently, the Company does not offer energy efficiency programs directed towards street lighting, and street lighting use is not metered and, as such, distribution revenues are fixed (Tr. 6, at 805-806; Tr. 8, at 1201-1202). Additionally, revenue decoupling was not intended to compensate a company for the sale of street lighting assets. D.P.U. 14-136-A, at 10; see D.P.U. 07-50-A. In the Department's decoupling investigation, we did not contemplate this potential issue, and the model we adopted to decouple rates for all future ratemaking proceedings was silent on street lighting rate classes in RDM. D.P.U. 07-50-B at 26.

For these reasons, the Department expects to address the issue of street lighting rate classes included in the revenue decoupling provisions in a future proceeding. In this regard, the Department puts the Company, and all electric distribution companies, on notice that it has concerns with the inclusion of street lighting rate classes in RDMs, and that we will consider removing street lighting rate classes from RDMs in each electric distribution company's next base distribution rate proceeding. Thus, as part of the initial filing in its next base distribution rate proceeding, each electric distribution company must address and provide justification for the continued inclusion of street lighting rate classes in each company's respective revenue decoupling provision.

V. CAPITAL INVESTMENT RECOVERY MECHANISM

A. Introduction

In the Company's last base rate case, the Department approved National Grid's revenue decoupling provision, which included a CapEx mechanism allowing 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.[19] In addition to the $170 million cap, the approved revenue decoupling provision includes a rate cap limiting the annual revenue decoupling adjustment (including the CapEx revenue requirement adjustment to the Annual Target Revenue ("ATR")) to three percent of total revenue (hereinafter referred to as the "rate cap"). D.P.U. 09-39, at 82, 87-88.

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 rate proceeding (Exh. NG-RRP-1, at 54). National Grid calculates each investment vintage year's revenue requirement using an average rate base methodology, incorporating accumulated depreciation and accumulated deferred income taxes associated with that vintage year's

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19 A review of the Company's capital investments made between the date of the decision in D.P.U. 09-39 and the end of the test year in this case is discussed in Section VII.B below.

investments (Exh. NG-RRP-1, at 54). The CapEx mechanism does not allow for the recovery of the revenue requirement for the year of investment for each vintage year, and the Company recovers the revenue requirement for the second year of each vintage beginning March 1st of the subsequent year (Exh. NG-RRP-1, at 54).[20]

B. Company Proposal

National Grid proposes to continue its existing CapEx mechanism with several modifications, including changing its name to the capital investment recovery mechanism ("CIRM") (Exhs. NG-MLR-1, at 16; NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22). The Company proposes to: (1) separate the CIRM from the traditional RDM reconciliation, and operate the mechanisms under separate tariffs; (2) increase the annual investment cap on capital expenditures from $170 million to $285 million; (3) include property taxes in the computation of the CIRM revenue requirement; and (4) apply a one-percent rate cap to the change in annual revenue requirement in the CIRM (Exhs. NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22).

As set forth in great detail below, the Attorney General opposes all of the proposed modifications. Instead, the Attorney General recommends that the Department should eliminate the CIRM entirely, or, in the alternative, do the following: (1) maintain the investment cap at $170 million, or in the alternative, set the cap at $183 million; (2) limit the scope of capital investments eligible for recovery; (3) include metrics, goals, and/or reporting to provide accountability of customer benefits associated with the Company's capital investments, and to

[20] The Company's current CapEx mechanism, and proposed capital investment recovery mechanism, imposes a 14-month lag on the recovery of the second year revenue requirement for each vintage investment year (Exh. DPU-6-17).

verify that costs are reasonable; (4) include an O&M offset, representing the savings associated with the capital investments; and (5) adjust the rate of return in the CIRM downward to reflect risk reduction associated with the Company's recovery of capital investment with little to no regulatory lag (Exh. AG-DO-CF-1, at 8, 11-12, 18-20; Attorney General Brief at 88-94; Attorney General Brief at 49-53).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General initially recommends discontinuance of the CIRM (Attorney General Brief at 85). The Attorney General maintains that her recommended modifications are necessary to control costs and limit spending to projects that are necessary to provide safe and reliable service (Attorney General Reply Brief at 52, citing Exh. NG-JHP-1, at 29). The Attorney General's specific arguments in support of these positions are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Attorney General recommends elimination of the CIRM entirely (Attorney General Brief at 85). According to the Attorney General, the Department allows alternative regulatory mechanisms only in cases of "extraordinary circumstances," where a company has demonstrated its need to recover incremental costs associated with specific programs between base distribution rate cases (Attorney General Brief at 85, citing Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121-122, 132-133 (2010); D.P.U. 09-39, at 79-80, 82; Bay State Gas Company, D.P.U. 09-30, at 133-134 (2009)). The Attorney General rejects any notion that the Company's investment needs are extraordinary, and she claims that many of these investments will be eligible for recovery through a separate recovery mechanism pending in the Grid Modernization Investigation, D.P.U. 15-120 (Attorney General Brief at 86, citing Company Brief at 97; Attorney General Reply Brief at 48, citing Exh. AG-DO-CF-1, at 12). Therefore, the Attorney General asserts that the Company failed to produce evidence of "extraordinary circumstances" to justify the continuation of the CIRM (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Moreover, the Attorney General argues that the Company is not in a unique position, nor is it under significant pressure to maintain a high degree of system reliability and resiliency, as it claims, because all utilities must invest in their systems for reliability (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 101; Attorney General Reply Brief at 47). Thus, the Attorney General argues that the Company's investment obligations are not extraordinary, but "standard operating procedure" (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Further, the Attorney General dismisses the Company's claim that the CIRM is necessary due to revenue decoupling (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 96-98). According to the Attorney General, the Department has previously rejected other companies' requests for a CIRM when those companies were unable to provide "compelling evidence of lost growth in sales" (Attorney General Brief at 86, citing Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 36 (2014); D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; D.P.U. 07-50-A at 50). In this regard, the Attorney General contends that revenue decoupling ensures the Company will be compensated for lost sales revenue associated with energy efficiency programs and distributed generation ("DG"), which the Company admits is causing its sales forecast to show declining growth (Attorney General Brief at 86-87, citing Exh. DPU-6-14, at 2; Attorney General Reply Brief at 48).[21] Therefore, the Attorney General asserts that because revenue decoupling will not remove the Company's ability to retain additional revenue between its base rate proceedings, there is no need for an additional recovery mechanism. (Attorney General Brief at 87, citing D.P.U. 10-70, at 47).

Additionally, the Attorney General alleges that the Company is financially healthy and highly liquid, and therefore, there is no need for the CIRM (Attorney General Reply Brief at 48). According to the Attorney General, the Company was allowed $40 million in base distribution rates for income taxes in its last base rate proceeding, but because of tax benefits the Company has not and will not pay income taxes for many years (Attorney General Reply Brief at 48, n.18, citing D.P.U. 09-39, at 457; Exh. NG-RRP-2, at 2, 30). Moreover, the Attorney General contends that the Company had sufficient cash available to lend hundreds of millions of dollars to its affiliates through the National Grid USA money pool over the last two years (Attorney General Reply Brief at 48, n.2 citing Exh. AG-1 (National Grid USA Money Pool Report)).

The Attorney General also argues that the Department should consider National Grid's proposed CIRM in conjunction with the Company's other reconciling mechanisms (Attorney General Reply Brief at 48). According to the Attorney General, the Company charges ratepayers on an annual basis for the following: (1) pensions and post-retirement benefits other than pensions ("PBOP") costs; (2) storm costs; (3) energy efficiency program costs; and (4) wind energy contract remuneration (Attorney General Reply Brief at 49, citing Exh. NG-RRP-2, at 2-3). The Attorney General argues that approving the CIRM and allowing these other

21 The Attorney General also notes that the Company receives compensation and incentives related to energy efficiency programs (Attorney General Reply Brief at 48).

reconciling mechanisms exposes ratepayers to an excessive share of risk (Attorney General Reply Brief at 49).

Finally, the Attorney General claims that the CIRM requires an annual prudency review and cost reconciliation, thereby adding to the Department's administrative burden (Attorney General Brief at 87). The Attorney General maintains that based on the Company's prior CIRM experience,[22] future prudency reviews will likely evolve into exhaustive investigations (Attorney General Brief at 87-88, citing docket D.P.U. 10-79; Exh. AG-DO-CF-1, at 35-56). For all these reasons, the Attorney General asserts that the Company's CIRM proposal is not in the best interest of ratepayers and should be discontinued (Attorney General Brief at 87-88; Attorney General Reply Brief at 48). As noted above, in the alternative, the Attorney General asserts that the Department should retain the current investment cap and make specific modifications to the Company's proposal, each of which are discussed below.

c. Investment Cap

The Attorney General argues that the CIRM "significantly reduces and potentially eliminates the important incentive that regulatory lag provides" to control costs because the Company is allowed to recover a return on and of its capital expenditures in the year that they are incurred (Attorney General Brief at 92, citing D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 50, citing D.P.U. 09-39, at 80-81). According to the Attorney General, the Department has found that in the absence of regulatory lag, a cap on the annual CIRM cost recovery would protect ratepayers from over-investment in capital infrastructure and still provide the Company

[22] The Attorney General claims that in National Grid's first CapEx investigation, the Company failed to provide project documentation in a timely manner and its filing ultimately lacked clear, cohesive, reviewable project documentation (Attorney General Brief at 88, citing Exh. AG-DO-CF-1, at 35-56).

with sufficient funds to ensure safe and reliable electric service (Attorney General Brief at 92, citing D.P.U. 09-39, at 81-82; Attorney General Reply Brief at 50). In this regard, the Attorney General contends that the Company budgeted for capital spending to align with the $170 million investment cap allowed by the Department when initially approving the CIRM (Attorney General Brief at 92, citing Exhs. DPU-6-7; DPU-18-5).[23] Thus, the Attorney General contends that the $170 million investment cap is an effective means of cost control, and National Grid may include plant additions above the investment cap in the rate base proposal in the Company's next base rate proceeding (Attorney General Brief at 92-93, citing D.P.U. 09-39, at 82-83). Further, she argues that increasing the investment cap will likely lead to a corresponding increase in unfettered capital spending, evident from the Company's capital investment forecast (Attorney General Brief at 92-93, citing Exh. AG-DO-CF-1, at 20; Attorney General Brief at 87, citing Exh. NG-JHP-1, at 29). For these reasons, the Attorney General recommends setting the investment cap at $170 million so as to balance the risk associated with the CIRM between shareholders and ratepayers (Attorney General Brief at 92, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 48, 49, 50, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80–81.).

In the alternative, if the Department decides to increase the investment cap from $170 million, the Attorney General argues that the Department should set the cap based on a representative level of historic spending, and not on forecasted spending (Attorney General Brief at 93; Attorney General Reply Brief at 50, citing D.P.U. 1580, at 13–17, 19; D.P.U. 136, at 3;

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23 However, she also alleges that the $170 million investment cap has not prevented the Company from exceeding it (Attorney General Reply Brief at 50, citing RR-DPU-13, Att.).

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; Attorney General Reply Brief at 51).[24] According to the Attorney General, when the Department grants a capital recovery mechanism, it bases it on an average of historical expenditures, not on company projections. (Attorney General Reply Brief at 51, citing D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82). Therefore, the Attorney General asserts that the investment cap should be based on a five-year average of plant additions (excluding cost of removal), instead of a three-year average[25] that the Department used to establish the $170 million investment cap (Attorney General Brief at 93, citing D.P.U. 09-39, at 82; D.P.U. 15-80/D.P.U. 15-81, at 53). The Attorney General maintains that a five-year average of plant additions (excluding cost of removal) is more appropriate than a three-year average because the Company's plant additions in 2013 and 2015 were not representative of a typical year (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).[26] Further, the Attorney General maintains that a five-year average for plant additions of $183 million provides an appropriate balance of sufficient funding for the Company and ensuring safe and reliable service (Attorney General Brief at 93, citing RR-DPU-14; Attorney General Reply Brief at 49, 51).

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24 The Attorney General alleges that the Company's proposed $285 million cap is based on future projections (Attorney General Reply Brief at 50-51).

25 The Attorney General calculates the Company's three-year average of plant additions (excluding cost of removal) at $197 million (Attorney General Brief at 93, citing RR-DPU-9).

26 The Attorney General explains that the Company's spending in 2015 was significantly higher than the prior years (i.e., $259 million in 2015; $180 million in 2014; $151 million in 2013; and $139 million in 2012), and in 2013, storm restoration efforts and issues related to the SAP implementation affected the Company's plant additions (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).

d. Modifications to the CapEx/CIRM

i. Scope

The Attorney General recommends that the Department direct the Company to narrow the scope of its CIRM to a certain category of spending (Attorney General Brief at 88; 89-90; Attorney General Reply Brief at 48, 49-50, 51). According to the Attorney General, a capital cost recovery mechanism is most effective when it is targeted to provide specific improvements and goals, and allows interested parties to track the costs associated with specific investment activities (Attorney General Brief at 88, citing D.P.U. 10-70, at 47-50; D.P.U. 10-55, at 66). The Attorney General explains that capital cost recovery mechanisms used by other states are more narrow and targeted compared to the Company's CIRM, and these mechanisms recover specific capital costs such as solar, renewable energy, or smart grid investments (Attorney General Brief at 88-89, citing Exh. AG-DO-CF-1, at 10-11; Tr. 15, at 1601-1603, 1683; Attorney General Reply Brief at 48-49, citing Tr. 15, at 1683). Additionally, the Attorney General explains that Connecticut Light and Power's ("CL&P") capital cost recovery mechanism authorizes recovery of specific projects that improve storm hardening infrastructure, and in 2013, represented an annual revenue requirement of $34.9 million (Attorney General Brief at 89, citing RR-NG-2, at 1; Attorney General Reply Brief at 52). The Attorney General does not make a specific recommendation regarding a spending category to limit the scope of the Company's CIRM, but she acknowledges that the Company already recovers costs for solar investments, smart grid technologies, and storm-related costs separately from the CIRM and base rates (Attorney General Brief at 89, citing Exhs. NG-RRP-1, at 107-110; AG-DO-CF-1, at 12; Tr. 15, at 1683).

ii. Benefits

The Attorney General recommends that the CIRM include a mechanism to account for customer benefits achieved in conjunction with annual capital spending (Attorney General Brief at 90, citing Exh. AG-DO-CF-1, at 13). The Attorney General claims that there is no evidence that National Grid's proposed CIRM will contribute to cost-effective, safe, and reliable service (Attorney General Brief at 90). For example, the Attorney General explains that the budget for "Asset Condition," which covers the replacement of assets the Company believes will fail, is forecasted to increase 116 percent over historical spending (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19-20). The Attorney General expects that this increase in spending would lead to a decrease or leveling out in the budget for "Damage/Failure," which covers the costs for the replacement of failed assets (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19). The Attorney General claims, however, that the Company's "Damage/Failure" budget category forecast for 2017-2019 increases 32 percent over historical spending (Attorney General Brief at 91, citing Exh. AG-7-5, Att.). From this data, the Attorney General contends that the Company is planning to replace assets with a low probability of failure to increase the costs recovered through the CIRM, thereby providing the Company with an opportunity for "gold-plating" (Attorney General Brief at 90-91, citing Exh. AG-7-5, Att.).

Further, the Attorney General maintains that other utilities include reports on the effectiveness of their capital cost recovery mechanisms (e.g., TIRF programs[27] include reports on leaks and CL&P provides data on system resiliency) (Attorney General Brief at 91,

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[27] TIRF refers to targeted infrastructure recovery factor programs that are designed to allow for annual recovery by gas distribution companies of the revenue requirement associated with incremental investment for the replacement of leak-prone infrastructure. See, e.g., D.P.U. 09-30, at 121.

citing Exh. AG-DO-CF-1, at 13, 16; RR-NG-2, Att. 2, at 11-12). The Attorney General asserts that there should be greater accountability in the Company's CIRM mechanism because it is much broader than a TIRF or CL&P's capital cost recovery mechanism (Attorney General Brief at 91). Therefore, the Attorney General recommends that the Department require the Company to re-engage with stakeholders to establish metrics, goals, and reporting requirements to ensure that the investments made in the CIRM deliver benefits to customers at a reasonable cost (Attorney General Brief at 91, citing Exh. AG-DO-CF-1, at 16-17; Attorney General Reply Brief at 52, n.20).

iii. O&M Offset

The Attorney General alleges that through the CIRM, National Grid will complete system replacements and enhancements, and as a result, the number and cost of failures will decline (Attorney General Brief at 91, citing Tr. 2, at 251-252; Attorney General Reply Brief at 52). For example, the Attorney General explains that the installation of reclosers on circuits would limit the area crews that the Company would need to patrol to locate outages (Attorney General Brief at 91, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). The Attorney General maintains that with a decline in outages, the Company also should experience lower O&M expenses (Attorney General Brief at 92, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). Therefore, the Attorney General recommends that the Company's CIRM include an O&M offset associated with the O&M savings resulting from additional capital investments (Attorney General Brief at 91-92, citing Exhs. AG-DO-CF-1, at 18; AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 50, 52, 53).

iv. Rate of Return

The Attorney General argues that if the Department decides to allow the CIRM as proposed by the Company, the Department should adjust downward the rate of return that the Company is allowed in the CIRM (Attorney General Brief at 94; Attorney General Reply Brief at 49, citing D.P.U. 07-50-A, at 71; Bay State Gas Company, D.T.E. 05-27, at 302 (2005); D.T.E. 02-24/02-25, at 229; D.T.E. 03-40, at 363; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977)). The Attorney General argues that a lower rate of return is reflective of the Company's reduction in risk associated with the recovery of most, if not all, of its capital investments in between base rate proceedings, with little regulatory lag (Attorney General Brief at 94, citing Exh. AG-DO-CF-1, at 20).

2. PowerOptions

PowerOptions argues that the Department must take a close look at proposed tracking mechanisms, such as the proposed CIRM, and decide whether they are warranted and in the best interest of ratepayers (PowerOptions Reply Brief at 9, citing D.P.U. 15-80/D.P.U. 15-81, at 47; 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.) According to PowerOptions, while the tracking mechanisms benefit utility companies in terms of timely cost recovery, they are administratively onerous with annual filings requiring review by all interested parties, require numerous reconciliations and true-ups, and often result in additional charges to customers beyond base rates (PowerOptions Reply Brief at 9-10). Further, PowerOptions notes that the Department has found that where a company failed to demonstrate there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers (PowerOptions Reply Brief at 10, citing D.P.U. 15-80/D.P.U. 15-81 at 54; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50-52).

Based on these considerations, PowerOptions argues that the Department must take a close look at whether extraordinary circumstances prevent National Grid from acquiring the capital necessary to make required investments in its infrastructure (PowerOptions Reply Brief at 10). PowerOptions contends that if the Department allows the CIRM, then it must decide whether an investment cap increase to $285 million is warranted and, if so, the Department needs to determine the process to ensure that there is appropriate oversight over these investments and proper review of the Company's three-year capital investment plan (PowerOptions Reply Brief at 10-11).

3. Company

a. Introduction

National Grid submits that its capital investments are increasing: (1) to maintain a resilient, modern electric grid substantially improved through technology; and (2) to meet customers' expectations for reliable service and information (Company Brief at 165). According to the Company, two modifications will improve the CIRM's operation (Company Brief at 166). First, National Grid proposes to increase the current investment cap of $170 million to $285 million, representative of the Company's actual plant additions during the test year (Company Brief at 166). Second, the Company proposes to include property tax expense in the computation of the revenue requirement because it is the "normal course for capital investment recovery mechanisms approved by the Department in other contexts" (Company Brief at 166).

The Company disagrees with the Attorney General's recommendation to eliminate the CIRM, and it rejects the Attorney General's alternative recommended modifications. The Company's positions regarding these issues are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Company argues that discontinuing the CIRM is implausible, especially considering the Commonwealth's energy efficiency programs, DG resources, and demand response programs that have been put in place since 2008 (Company Brief at 168). According to National Grid, the Department has recognized the direct impact on the Company's business when average consumption declines as a result of these conservation initiatives, namely the Company's inability to retain incremental sales revenue to support capital investment on a year-to-year basis (Company Brief at 168-169). National Grid acknowledges that revenue decoupling reimburses the Company for lost sales revenue due to reductions in consumption since setting its ATR (Company Brief at 165-166). However, the Company maintains that revenue decoupling also negates growth in sales that would have supported increases in the Company's cost of service between base rate proceedings (Company Brief at 165-166).[28] Thus, National Grid disagrees with the Attorney General's assertion that, through decoupling, the Company already is reimbursed and made whole for sales losses due to energy efficiency (Company Reply Brief at 69, citing Attorney General Reply Brief at 48).

Instead, National Grid contends that revenue decoupling does not return the value of sales volumes to the Company that is over and above the test year and were historically available to fund capital expenditures between base rate proceedings (Company Reply Brief at 70).

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[28] National Grid attributes increases in the cost of service largely to capital investment since its last base rate proceeding (Company Brief at 165-166).

According to National Grid, the Attorney General has failed to discredit evidence provided by the Company that the CIRM is necessary as a result of the Department's efforts to promote energy efficiency, demand resources, renewable energy, and DG (Company Reply Brief at 69, citing Exh. DPU-6-14). Thus, National Grid argues that if its revenues are decoupled from sales, the Company must retain its CIRM with the proposed modifications (Company Brief at 169-170).

Further, National Grid claims that its declining sales forecast demonstrates the success of the Department's efforts to achieve the objectives in D.P.U. 07-50-A (Company Brief at 170). According to the Company, without the downward sales pressure from DG and energy efficiency, the Company would have realized sales growth to offset its plant additions (Company Brief at 170, 171, citing Exh. DPU-6-14, Att.; Company Reply Brief at 69). According to the Company, the Attorney General did not rebut, evaluate, critique, or challenge: (1) the Company's sales forecast; or (2) that the Company's energy efficiency savings as a percent of total kilowatt hour ("kWh") delivery have doubled since 2010 (Company Reply Brief at 69; Company Brief at 168, citing Exh. NG-MLR-1, at 13).

Moreover, National Grid disputes the Attorney General's argument that the Company receives compensation and incentives for its energy efficiency programs (Company Reply Brief at 70). National Grid maintains that energy efficiency program costs are passed through to customers and any incentives that the Company receives are not sufficient to fund the Company's plant additions (Company Reply Brief at 70). For all these reasons, the Company asserts that the Attorney General did not provide creditable evidence in support of her position to discontinue the Company's CIRM (Company Reply Brief at 70).

c. Investment Cap

In response to the Attorney General, the Company argues that the current $170 million investment cap is insufficient for recovery of annual capital expenditures (Company Brief at 173). According to the Company, it has exceeded the $170 million cap by a total of $178 million since the CIRM's implementation (Company Brief at 173). Additionally, the Company argues that its plant additions and cost of removal in the test year alone exceeded the $170 million cap by more than $100 million (Company Brief at 173). Therefore, the Company asserts that the Attorney General's recommendation to set the investment cap at either $170 million or $183 million is not supported by record evidence (Company Reply Brief at 73).

In support of the proposed $285 million investment cap, the Company argues that it is under pressure to meet expanding service requirements and increased investment in distribution infrastructure (Company Brief at 166, citing Exh. NG-RRP-1, at 60). The Company maintains that it cannot meet the growing demand for capital investment without the CIRM, and that it will need to spend up to the $285 million investment cap to continue to meet its capital investment goals over the next three years (Company Brief at 167, citing Exh. NG-RRP-1, at 60; Company Reply Brief at 72, citing Exh. NG-JHP-1, at 29). The Company notes that it invested approximately $1.3 billion in its system between the end of 2008 and June 30, 2015 (Company Brief at 166, citing Exh. NG-RRP-1, at 60). Further, National Grid points out that it incurred $260 million in plant in service and $25 million in cost of removal in the test year (Company Brief at 166-167, citing Exh. DPU-32-22). Therefore, the Company asserts that a $285 million investment cap, based on actual capital expenditures in the test year, is more representative of the

Company's actual and projected investments (Company Brief at 174, citing Exh. NG-JHP-1, at 29).

National Grid also argues that increasing the investment cap to $285 million is in the best interest of ratepayers because it will contribute to maintaining service at current levels and assist the Company in complying with the Department's service-reliability metrics (Company Brief at 176, citing Exh. AG-7-5; Company Reply Brief at 73). National Grid claims that an investment cap based on a historical three-year or five-year average will not achieve the intended capital investment cost recovery and will render the CIRM moot (Company Brief at 174). In the alternative, the Company suggests that the Department approve a rolling three-year average investment cap, up to $285 million (Company Brief at 174, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277; Company Reply Brief at 73, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277).

d. Property Taxes

National Grid notes that the Attorney General did not challenge the Company's proposal to include property taxes in the CIRM (Company Reply Brief at 73). In support of the property tax modification, the Company explains that the current CIRM does not allow for recovery of property tax associated with annual capital additions made after the test year, which National Grid claims contradicts the Department's standard practice (Company Brief at 167, citing Exh. NG-RRP-1, at 62). The Company maintains that every other capital recovery mechanism approved by the Department includes property tax recovery, except for the recent mechanism approved for Fitchburg Gas and Electric Light Company (Company Brief at 162, 167, citing D.P.U. 15-80/D.P.U. 15-81, at 54; Tr. 1, at 95-96; Boston Edison

Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-82-A, at 53, 61 (2010)). The Company purports that incremental capital investment causes incremental increases in property tax (Company Brief at 167, citing Exh. DPU-10-2). Thus, National Grid argues that property taxes are directly attributable to the Company's capital additions and an unavoidable element of the CIRM revenue requirement (Company Brief at 167, citing Exh. NG-RRP-1, at 62). Additionally, the Company adds that the Department did not perform an investigation that would provide a foundation to exclude property tax from the CIRM (Company Brief at 167).

Moreover, National Grid claims that it did not originally propose to include property taxes in its CapEx proposal in D.P.U. 09-39 because the mechanism was one of four proposed rate recovery mechanisms: (1) the approved RDM; (2) the approved CapEx mechanism; (3) a proposed CapEx mechanism to recover projected capital investments; and (4) a proposed adjustment mechanism for net inflation (Company Brief at 161-162, citing D.P.U. 09-39, at 10). National Grid claims that it did not propose to recover property taxes in the approved CapEx mechanism because its proposed net inflation adjustment mechanism would have adjusted its total operating expense, including property taxes (Company Brief at 162, citing D.P.U. 09-39, Exh. NG-HSG-RR-8, at 2). The Company asserts that the Department did not "correct for this purposeful exclusion when it approved capital-cost recovery, while denying the net inflation adjustment" (Company Brief at 162). National Grid describes this result as an "inadvertent exclusion" and a "mistake" by the Department in D.P.U. 09-39 (Company Brief at 162). Therefore, National Grid concludes that there is no basis to exclude property taxes in the calculation of the CIRM revenue requirement in the instant proceeding (Company Brief at 167; Company Reply Brief at 73).

e. Response to Attorney General's Recommended Modifications

The Attorney General recommends several modifications to the CIRM that National Grid claims lack justification, are unsubstantiated, and are contrary to the purposes of the CIRM (Company Brief at 176; Company Brief at 171-172, citing Attorney General Brief at 88; Company Reply Brief at 70). The Company argues that the Attorney General failed to provide persuasive testimonial evidence to support her recommended modifications to the proposed CIRM (Company Reply Brief at 71-72, citing Tr. 15, at 1602-1605, 1607-1608, 1613, 1617-1618, 1622-1628, 1630-1632). Further, National Grid contends that the Attorney General did not provide analytical support for any of her proposed modifications (Company Reply Brief at 71).

i. Scope

National Grid claims that the Attorney General's recommendation to narrow the scope of cost recovery in the Company's proposed CIRM, based on the design of capital cost recovery mechanisms in other jurisdictions, is unsubstantiated (Company Brief at 172, citing Attorney General Brief at 89; Tr. 15, at 1600-1609). In particular, the Company argues that the Attorney General's evidence of CL&P's storm hardening cost recovery mechanism is actually tied to a capital budget recovered though CL&P's base rates on a future test year basis (Company Brief at 172, citing RR-NG-2, Att. at 1, 8). Therefore, National Grid asserts that capital cost recovery is more favorable to electric distribution utilities in Connecticut than Massachusetts, a fact that the Company claims the Attorney General failed to recognize (Company Brief at 172-173).

ii. Benefits

The Company rejects the Attorney General's recommendation that the Department should include metrics to improve the accountability of customer benefits from the Company's capital spending in the CIRM (Company Brief at 176). The Company maintains that the Attorney General did not explain how the Department's existing service-quality metrics are deficient or suggest an alternative mechanism to include in the CIRM (Company Brief at 176).

iii. O&M Offset

National Grid contends that the Attorney General did not support her position to include an O&M offset in the CIRM (Company Brief at 176; Company Reply Brief at 73). The Company maintains that the O&M offset in the gas system enhancement plan cost recovery mechanism represents the elimination of a discrete O&M expense caused by gas leaks that no longer need repairs because the leaky pipe was replaced (Attorney General Brief at 176). According to the Company, there are no similarities in O&M savings between the CIRM and the gas system enhancement plan (Company Brief at 176; Company Reply Brief at 73).

iv. Rate of Return

Finally, the Company claims that the Attorney General did not rebut the Company's evidence showing that a deduction to the cost of capital is not warranted or appropriate (Company Brief at 176). Therefore, National Grid asserts that the Attorney General's modification to the rate of return on invested capital should be denied (Company Brief at 173, 176).

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 rate proceedings -- revenues that companies could have used to pay for increased O&M costs, costs related to system reliability, and capital expansion projects. See 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 that adjust target revenues to account for capital spending and inflation but that a company would bear the burden of demonstrating the reasonableness of its proposal. D.P.U. 07-50-A at 50; see also D.P.U. 11-01/D.P.U. 11-02, at 107-108; D.P.U. 10-70, at 47.

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.[29] The Department has allowed capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover

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[29] National Grid was the first electric distribution company to receive approval for a CapEx mechanism following revenue decoupling. D.P.U. 09-39, at 80-84. Subsequently, the Department approved a CapEx 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 CapEx mechanism for Western Massachusetts Electric Company. D.P.U. 10-70, at 52.

incremental costs associated with capital expenditure programs between base rate proceedings. 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. Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve a capital cost recovery mechanism as an element of decoupling. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; see also D.P.U. 07-50-A at 50. The Department has found that, where a company failed to demonstrate that there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers. D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50, 52.

2. Continuation of the CapEx/CIRM

National Grid acknowledges that the CapEx mechanism approved by the Department in D.P.U. 09-39 has not provided the Company with the level of benefits expected when originally proposed (Exh. NG-RRP-1, at 60-62). Thus, the Company proposes to increase the investment cap in its CIRM from $170 million to $285 million and apply a one-percent rate cap to the change in annual revenue requirement (Exhs. NG-RRP-1, at 61-62; DPU-32-22). Additionally, National Grid argues that the current CapEx mechanism does not provide for recovery of property taxes, a direct component of capital investment (Exhs. NG-RRP-1, at 62; DPU-10-2). Accordingly, the Company has proposed a modified CIRM that includes an investment cap of $285 million and for recovery of property taxes based on the ratio of test year property taxes to rate base (Exh. NG-RRP-1, at 61-62).

The Company must meet its service requirements and investment in distribution infrastructure, which has steadily increased since its last rate case (Exhs. NG-RRP-1, at 60; NG-MLR-1, at 6; DPU-18-5). See Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57 (2009) (a monopoly service provider has a public service obligation to provide reliable service at the lowest cost to customers); Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 6-7 (1986); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). National Grid invested approximately $1.3 billion in its electric distribution system from 2009 through June 30, 2015, and its actual expenditures on capital investment have exceeded the $170 million annual investment cap by an aggregate $178 million over the same period (Exhs. NG-RRP-1, at 60-61; AG-7-5, Att.; AG-16-2, Att.). The Company expects that its workload will increase significantly to provide safe and reliable service and it forecasts capital expenditures to increase from $302 million in 2015 to $311 million in 2017 (Exhs. DPU-10-6; DPU-18-5; AG-7-5). Moreover, the Company's test year plant additions were more than twice the level of the Company's depreciation expense of $127 million (Exhs. NG-RRP-1, at 60; NG-RRP-2, at 5 (Rev. 3)). Accordingly, National Grid would be unable to fully fund its test year level of capital expenditures, much less fully fund its projected increases in capital expenditures, through its base rate depreciation expense.[30]

National Grid also is experiencing an unprecedented level of DG and energy efficiency installations on its system, which cause diminishing sales revenues and increasing workload and expenses to administer the interconnection process for these installations (Exhs. NG-MLR-1,

[30] Depreciation expense is a non-cash expense associated with the use of an asset. Utilities often use depreciation expense as a funding source for capital expenditures.

at 13, 19; DPU-6-21). The Company ranks fifth in the United States in solar interconnections, at 405.3 megawatts (“MW”) of interconnected DG solar over the period 2009-2015 (Exh. NG-MLR-1, at 19-20). Without the effect of increasing DG and energy efficiency, the Company’s sales forecast derived solely on the basis of economic data would show positive sales growth over a five-year planning period (Exh. DPU-6-14, at 3). Thus, the Company estimates that DG and energy efficiency are reducing sales by approximately 2.3 percent cumulatively per year based on historical installations, and could increase to sales reductions of 6.5 percent cumulatively per year over a five-year planning period, based on additional installations (Exhs. DPU-6-14, at 4; DPU-6-14, Att. at 21).

Based on these considerations, the Department finds that the Company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate cases. Accordingly, we will allow the operation of the Company’s CIRM. D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. In this regard, we further find that the CIRM shall operate independent of the Company’s revenue decoupling provision. Although the Department stated that we would consider proposals to adjust ATR in an RDM, separating the mechanisms produces the same result for the Company. The RDM reconciliation will annually true-up the over- or under-recovery of base distribution rates, while the CIRM will annually true-up the over- or under-recovery of the Company’s allowed annual capital expenditure. See D.P.U. 07-50-A at 50. Separating the CIRM component from the RDM allows for administrative efficiency and the application of separate rate caps.

National Grid proposes an annual rate cap on the CIRM revenue requirement at one percent of total revenues (Exh. NG-PP-23, at 178, (proposed M.D.P.U. No. 1277, at sheet 3)). The Department finds that a one-percent rate cap adequately protects ratepayers from excessive annual increases to distribution rates. See D.P.U. 10-55, at 133. To the extent that the application of the one-percent rate cap results in a CIRM revenue requirement that is less than that calculated, National Grid shall defer the difference and include in the CIRM reconciliation for recovery in the subsequent year. Carrying charges shall be calculated on the average deferred balance using the customer deposit rate (Exh. NG-PP-23, at 178 (proposed M.D.P.U. No. 1277, at sheet 3)). Additionally, the one-percent rate cap is consistent with other capital tracking mechanisms approved for utilities in Massachusetts. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 53-54; D.P.U. 10-55, at 133.

The Department now allows the Company's CIRM to operate separately from the Company's revenue decoupling provision. Below, the Department addresses the Company's proposed modification to increase the investment cap to $285 million and to include property taxes in the annual revenue requirement. We also address the Attorney General's recommended modifications to the CIRM.

3. Investment Cap

The Company proposes to increase its investment cap to $285 million, based on its test year plant additions and cost of removal (Exhs. NG-RRP-1, at 61; DPU-10-6, Att.; RR-DPU-9; RR-DPU-14). The Attorney General asserts that the investment cap should remain at $170 million, or in the alternative, be set at $183 million, representing the five-year average of plant additions, excluding cost of removal (Exh. AG-DO-CF-1, at 8; Attorney General Brief at 93, citing RR-DPU-14).

Capital cost recovery mechanisms reduce and potentially eliminate the important incentive that regulatory lag provides to companies to maintain an appropriate balance between investing in capital improvements and incurring O&M expenses. D.P.U. 09-39, at 81. To reach a balance between: (1) providing the Company with sufficient capital funding to ensure the safety and reliability of the electric service that it provides to its ratepayers; and (2) protecting its ratepayers against the incentive the Company has to overinvest in capital infrastructure in order provide earnings to its shareholders, the Department has directed companies to implement investment caps. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 81-82.

After review of the record and the arguments of the parties, the Department finds it appropriate to implement an investment cap based on the historical three-year average of capital spending, or $249 million (Exh. DPU-10-6 & Att.).[31] We conclude that using this three-year average of capital spending as the limit on CIRM revenue requirement is appropriate because it is representative of National Grid's current capital investment needs and, as such, strikes the appropriate balance between: (1) providing the Company with sufficient funds to ensure safe and reliable electric service; and (2) protecting ratepayers from over-investment in capital infrastructure. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82.[32]

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31 The $249 million historical three-year average of capital spending (including cost of removal) is calculated based on capital spending of approximately $176 million in 2013, $270 million in 2014, and $302 million in 2015 (Exh. DPU-10-6 & Att.).

32 The Department expects the Company's first CIRM filing to reflect six months of capital investments (i.e., July 1, 2015-December 31, 2015). Therefore, the Department directs the Company to prorate the annual $249 million investment cap (i.e., $124.5 million) to

The Department makes no determination regarding the optimal level of investment the Company should make in its distribution infrastructure in order to provide safe and reliable electric service to its ratepayers in satisfaction of its public service obligation.[33] The Company's maintenance and replacement activities may lead the Company to identify capital investments that exceed the level of the three-year average

4. Property Taxes

In D.P.U. 15-80/D.P.U. 15-81, the Department excluded property taxes from Fitchburg Gas and Electric Light Company's capital cost recovery mechanism on the basis that capital cost recovery mechanisms are not intended to provide a company with dollar-for-dollar recovery of capital investments between rate cases, and are intended to provide rate relief in between base distribution rate cases to fund capital investments that otherwise were available to be funded through sales growth prior to decoupling. D.P.U. 15-80/D.P.U. 15-81, at 54. Based on the record in this proceeding, however, it is apparent that the exclusion of property taxes does not provide the appropriate rate relief between base rate proceedings to fund capital investments that were available to be funded through sales growth prior to revenue decoupling (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Further, based on the record in this proceeding, the Department is persuaded that property taxes are directly attributable to the Company's capital additions (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Incremental increases in property taxes are inextricably linked to incremental

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account for only six months of capital investment in the first annual CIRM filing following this Order.

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

capital investment funded through the CIRM. Moreover, under the Company's current CapEx mechanism, the Company's return on rate base was 1.18 percent (compared to its authorized return of 8.14 percent) (Exhs. NG-MLR-1, at 4; AG-16-1). See also Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39-A at 38 (2010). The Department concludes property taxes represent a significant cost related to capital investments, and excluding them from the CIRM may contribute to earnings erosion and may negatively affect capital investment.

We recognize that the Department's decision today shifts from the policy direction previously stated in D.P.U. 15-80/D.P.U. 15-81. However, we find that the change here is necessary in order to provide the Company with a necessary and appropriate level of rate relief. Moreover, the Department's goal in the inclusion of property taxes in the CIRM is to mitigate the need for base rate relief prior to the five-year interval prescribed by § 94, ultimately to the benefit of ratepayers. Further, we note that permitting the Company to recover property taxes associated with CIRM investments will not result in dollar-for-dollar recovery of all property taxes. The Company proposes to include property taxes in its CIRM using a ratio of total annual property taxes paid in the test year to total taxable net plant in service in the test year (Exhs. NG-PP-23, at 176 (proposed M.D.P.U. No. 1277, at sheet 1); DPU-18-8, Att.). Based on the Company's original cost of service data, the property tax rate for the CIRM calculation is 2.63 percent (Exhs. NG-RRP-2, at 28, 30 (Rev. 1); DPU-18-8). The Company multiplies the 2.63 percent property tax rate by net plant to determine the property tax expense recoverable through the CIRM (Exh. DPU-18-8). Because National Grid is not permitted to recover the revenue requirement associated with the investment vintage year, the full property tax expense on CIRM investments are not fully realized in the CIRM until the third year's revenue requirement calculation (Exh. DPU-18-8). Therefore, property taxes recoverable in the CIRM are not actual incurred expenses on the new CIRM investment in the vintage year.[34]

Further, based on a CIRM with an investment cap of $285 million (i.e., the Company's proposal), National Grid would not collect property taxes for the first year of the investment, and in the second and third years of the CIRM, it would collect approximately $3 million and $6 million, respectively, associated with only the first year of capital investment (Exh. DPU-18-8, Att. at 1). In addition, to the extent that the Company's annual capital investment exceeds the investment cap, the Company will not recover property taxes associated with these investments until its next base rate case. Therefore, the Company's CIRM retains a measure of regulatory lag. For all of the foregoing reasons, the Department allows the Company's proposal to include property taxes in the calculation of the CIRM revenue requirement.

5. Attorney General's Modifications

The Department declines to adopt the Attorney General's recommendations to limit the scope of the CIRM and to implement an O&M offset. The Attorney General did not provide persuasive evidence on how or what to limit the scope of the CIRM or provide sufficient quantification of any O&M offset (see Exhs. AG-DO-CF-1, at 11-12, 18-19;

34 Moreover, the property tax expense associated with CIRM investments is not based on actual property tax bills. Thus, annual incremental property taxes associated with CIRM investments are not recovered on a dollar-for-dollar basis.

AG-DO-CF-Rebuttal-1, at 7-9).[35] Finally, we find that the Attorney General did not substantiate with appropriate analysis her recommendation for a lower rate of return applicable to the CIRM. Therefore, we decline to adopt her recommendation. The Department discusses the Company's overall rate of return, and whether the approved CIRM reduces risk, in Section XII.E below.

Regarding benefits, the Attorney General recommends that the Department require the Company to re-engage with stakeholders to establish metrics, goals, and reporting requirements to ensure that the investments made in the CIRM deliver benefits to customers at a reasonable cost (Attorney General Brief at 91, citing Exh. AG-DO-CF-1, at 16-17; Attorney General Reply Brief at 52, n.20). See D.P.U. 09-39, at 84. After the Department's directive in D.P.U. 09-39, the Company coordinated three meetings to develop capital spending metrics for future years (Exh. DPU-18-6). National Grid was unable to reach an agreement on the purpose or iteration of the metrics as of April 4, 2012 (Exh. DPU-18-6). The Company stated that because the annual CapEx mechanism proceedings were suspended, it did not re-engage stakeholders to reach an agreement (Exh. DPU-18-6).

With this Order, the previous CapEx mechanism proceedings will be resolved (see Section VII.B.6). However, the Company will continue to make future CIRM filings. Thus, the Department directs the Company to continue to work toward the development of a capital plan that includes goals and metrics by which to measure and quantify its success. Accordingly, within 120 days of the date of this Order, National Grid shall provide the Department with a report detailing the Company's efforts to develop such goals and metrics. In conjunction with this report, the Company shall update and file the Proposed Capital Plan Metrics Capital Plan

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[35] Despite making this recommendation, the Attorney General could not point to any such category or external factor to limit the scope of the CIRM (Exh. AG-DO-CF-1, at 11-12).

labeled as Exhibits AG-4-9-A and AG-4-9-B in docket D.P.U. 11-60. Upon review of the Company's filing, the Department will determine the appropriate next steps.

6. Conclusion

The Department allows the Company's proposal to operate the CIRM outside of the RDM. The Department also approves a modified investment cap of $249 million, a one-percent rate cap, and the Company's proposal to include property taxes in the CIRM revenue requirement. In compliance with this Order, the Department directs the Company to modify its CIRM tariff according to the foregoing directives. Further, the Company shall make all future CIRM filings in compliance with the directives set forth in Section VII.B.5.b.viii below.

VI. STORM COST RECOVERY MECHANISM

A. Introduction

1. Background of the Storm Fund

Pursuant to a rate plan settlement in D.T.E. 99-47 ("D.T.E. 99-47 Settlement"), the Department approved the collection by the Company of $4.3 million annually in base rates for contribution to a storm fund. In accordance with the terms of the D.T.E. 99-47 Settlement, the Company was permitted to access the storm fund when the cost of responding to an individual storm exceeded $1.25 million. D.T.E. 99-47 Settlement, Att. 5. The D.T.E. 99-47 Settlement also established a cap on the storm fund balance of $20 million, adjusted for inflation, applicable to the storm fund. D.T.E. 99-47 Settlement at 15. In the event the cap was exceeded (either positive or negative), the excess or deficiency was to be recovered or refunded over a five-year period. D.T.E. 99-47 Settlement, at 15. Finally, the D.T.E. 99-47 Settlement provided for interest to be applied on the storm fund balance (or deficit) at the customer deposit rate. D.T.E. 99-47 Settlement, Att. 5.

In the Company's last base rate case, D.P.U. 09-39, the Department approved the Company's proposal to continue the storm fund, but also determined that several modifications to the storm fund were necessary. D.P.U. 09-39, at 205-213. The Department maintained the annual storm fund collection of $4.3 million in base rates. D.P.U. 09-39, at 207. However, the Department rejected the Company's request to recover through the storm fund all expenses associated with an individual storm that exceeds $1.25 million in restoration costs, and instead permitted the Company to recover only the costs in excess of $1.25 million. D.P.U. 09-39, at 207. Further, the Department rejected the Company's proposal to carry a credit balance in the storm fund at the customer deposit rate and a deficit balance at the weighted average cost of capital ("WACC"). D.P.U. 09-39, at 207. Instead, the Department found it appropriate for the storm fund balance (whether credit or deficit) to accrue interest at the Company's WACC determined in that proceeding. D.P.U. 09-39, at 208.

In addition, National Grid proposed to remove the cap on the fund balance on the credit side and, if the storm fund had a deficit balance in excess of $8.6 million, include on an annual basis the amount in excess of $8.6 million as a distribution adjustment with carrying costs at the Company's WACC. D.P.U. 09-39, at 208. The Department rejected this proposal and instead continued the symmetrical cap of $20 million. D.P.U. 09-39, at 208. The Department found that in the event the cap was exceeded as the result of a surplus, then the amount over the cap collected from ratepayers in that year would be returned in the following year. D.P.U. 09-39, at 208.[36] In the event the cap was exceeded as a result of a deficiency, the Company would have the option to propose to the Department an alternative method for recovery of incremental costs that exceed the cap. D.P.U. 09-39, at 208-209.

Finally, the Department found that in order to recover any costs from the storm fund, National Grid must obtain approval from the Department by demonstrating that the costs the Company seeks to recover from the fund are storm related, incremental, exceed the $1.25 million threshold, and were prudently incurred. D.P.U. 09-39, at 209. National Grid was directed to submit as part of its filing a report that outlines the total number and costs of all storms that occurred in the past year. D.P.U. 09-39, at 209.

2. Storm Cost Recovery Filings

Pursuant to the directives set forth in D.P.U. 09-39, the Company petitioned the Department in March 2013 for recovery of the $212 million storm fund deficit balance related to 14 storms that took place between February 2010 and February 2013. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-59, at 1-2, 4 & n.2 (2013). The Department approved a Storm Fund Replenishment Adjustment Factor ("SFRF")[37] designed to replenish the storm fund by $40 million annually for three years, beginning on May 4, 2013.

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[36] The Department found that consistent with the treatment of the recovery and reconciliation of pension costs and gas costs (220 C.M.R. § 6.08(2) for gas costs), the amount of storm costs to be reconciled would be returned through a kWh delivery surcharge with carrying costs on the reconciliation of forecast to actual recovery at the prime rate. D.P.U. 09-39, at 208, citing NSTAR Pension, D.T.E. 03-47-A at 46 (2003).

[37] Also referred to in other cases as the Storm Fund Replenishment Adjustment.

D.P.U. 13-59, at 14.[38] The Department also directed National Grid to file for a prudency review, no later than May 31, 2013, to include all supporting invoices for storm events that occurred between 2010-2011, and to file no later than December 31, 2013, for storm events occurring through February 2013. D.P.U. 13-59, at 2, 15.

Pursuant to the Department's directives in D.P.U. 13-59, the Company filed for recovery of the deficit balance in the storm fund associated with the incremental costs for eight storms that occurred between February 2010 and October 2011, and for eight storms that occurred between January 2012 and March 2013. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-85, at 1 (2016).[39] In D.P.U. 13-85, the Department approved the recovery of costs associated with these storms. D.P.U. 13-85, at 101, 106.[40] The Department also extended the SFRF through June 2018, because it will eliminate the storm fund deficiency associated with these 16 storms and will avoid approximately $7.6 million in carrying changes, to the benefit of ratepayers. D.P.U. 13-85, at 105.

According to the Company, between November 2013 and February 2015, there have been nine additional storms that qualify for recovery under the storm fund (Exh. NG-RRP-1,

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38 In a separate proceeding, the Department approved the transfer to the SFRF of recovery of outstanding costs related to a 2008 ice storm. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-85, at 7 (2014).

39 The 16 storms for which the Company sought cost recovery included the 14 aforementioned storms and two additional storms that occurred in 2013.

40 The final amount of approved costs is subject to confirmation by the Department following the Company's compliance filing in that proceeding. D.P.U. 13-85, at 101, 106.

at 67-68).[41] Thus, since 2010, there have been 25 storms that qualified for recovery through the storm fund (Exh. NG-RRP-1, at 68, 75). The net amount of incremental O&M expense eligible for reimbursement from the storm fund for these 25 events in total is $243 million (Exh. NG-RRP-2, at 26 (Rev. 3)).

B. Company Proposal

The Company proposes to continue its storm fund and to maintain the current $1.25 million cost-per-storm threshold for accessing the storm fund (Exhs. NG-RRP-1, at 68-69; DPU-21-17). However, the Company proposes four modifications to the current storm fund. First, the Company proposes to extend the SFRF to August 2019 in order to continue the more rapid replenishment of the existing storm fund to account for the nine additional qualifying storm event costs that took place after the Company's filing in D.P.U. 13-85, and to minimize the carrying costs associated with those storms (projected to be $32 million at the start of the rate year) (Exhs.NG-RRP-1, at 68-69, 78, 82; NG-RRP-6c, at 2). In this regard, the Company also proposes to transfer the deficit balance to be collected through the SFRF to a separate regulatory asset, and reset the storm fund balance to zero (Exh. NG-RRP-1, at 78). Further, the Company proposes that any residual balance (either positive or negative) remaining in the regulatory asset at the end of the extended recovery period (i.e., August 2019) then would be transferred to the Company's storm fund (Exh. NG-RRP-1, at 78-79).

Second, the Company proposes to increase from $4.3 million to $14 million, the amount collected annually through base rates and designated to the storm fund (Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 4, 26 (Rev. 3)). The Company states that based on its history of storm

41 The Company has not yet filed for a prudency review of these nine storms (Exh. NG-RRP-1, at 82).

events since its last rate case this proposal provides a more appropriate amount for the base-rate contribution, balances customer rate impact, and normalizes cost recovery for extraordinary storm events (Exh. NG-RRP-1, at 69, 86). In calculating the proposed base rate amount, the Company first eliminated from consideration $150 million in costs related to the three costliest storms that occurred between 2009 and June 30, 2015 (Exhs. NG-RRP-1, at 86; NG-RRP-2, at 26).[42] The Company then took an average of the remaining $93 million in storms costs ($243 million in net incremental storm costs minus $150 million) over the number of months between the end of the test year in D.P.U. 09-39 and the end of the test year in the instant proceeding, or 78 months, to arrive at an annualized amount of $14.0 million (Exhs. NG-RRP-1, at 86; NG-RRP-2, at 26 (Rev. 3)).

Third, the Company proposes to increase the storm fund's symmetrical cap on the balance in the fund from $20 million to $30 million to coincide with its proposed increase in the annual base rate contribution for storm costs (Exhs. NG-RRP-1, at 88-89). The Company states that it is necessary to raise the cap to $30 million in order to minimize the potential for frequent rate changes, either positive or negative (Exh. NG-RRP-1, at 89).

Fourth, the Company proposes to modify the current method by which carrying costs are applied to storm costs that are recovered through the storm fund, so that interest will accrue on incremental storm costs when such costs are filed for recovery with the Department (as opposed to when these costs are incurred) (Exh. NG-RRP-1, at 87). In this regard, the Company proposes that interest will accrue on the combination of the storm fund reserve and the costs related to the

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[42] These three storms were: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; and (3) Nor'easter Nemo in February 2013 (Exh. NG-RRP-1, at 86).

storms filed for storm fund cost recovery (Exh. NG-RRP-1, at 88). If the storm fund balance is in a surplus, then the Company proposes that interest will accrue at a carrying charge rate equivalent to the Company's pre-tax WACC, as determined by the Department (Exh. NG-RRP-1, at 87). Conversely, if the combined storm fund balance is in a deficit, then the amount in deficit (up to the $30 million cap) would accrue interest at the Company's customer deposit rate (Exh. NG-RRP-1, at 88). Further, any storm fund deficit in excess of the proposed $30 million storm cap would accrue interest at a carrying charge rate equivalent to the pre-tax WACC (Exh. NG-RRP-1, at 88).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that National Grid's storm fund should be eliminated because the Company failed to demonstrate that: (1) storm costs represent "extraordinary circumstances"; and (2) the storm fund is in the best interest of ratepayers (Attorney General Brief at 94-97, citing D.P.U. 13-90, at 14; Attorney General Reply Brief at 53, 57-58). Instead, the Attorney General asserts that the Company should recover storm costs through base distribution rates at a representative historical level (Attorney General Brief at 95). According to the Attorney General, if a storm results in extraordinary costs, National Grid could: (1) request from the Department deferral of these costs for consideration of recovery in its next base rate case; or (2) file for storm cost recovery through a base rate case proceeding, thereby allowing the storm costs to be weighed along with other factors affecting the Company's financial stability (Attorney General Brief at 95). On this last point, the Attorney General notes that annual rate cases should not be the norm if the storm fund is discontinued, and that the Company has a fiduciary obligation to act in the best interest of ratepayers and provide safe, reliable, and least-cost service (Attorney General Reply Brief at 57-58, citing D.P.U. 10-70, at 229 n.123; Incentive Regulation, D.P.U. 94-158, at 3 (1995); Integrated Resource Planning, D.P.U. 94-164, at 51-52 (1995)).

Alternatively, the Attorney General argues that if the Department continues the Company's storm fund, three revisions should be made. First, she contends that the cost-per-storm threshold to access the storm fund should be increased from $1.25 million to $2.4 million (Attorney General Brief at 98; Attorney General Reply Brief at 56-57). According to the Attorney General, storm costs have increased over time and this proposed threshold more accurately reflects the increase in costs (Attorney General Brief at 98, citing Exh. DPU-AG-1-9; Attorney General Reply Brief at 55-56). She also contends that under the current threshold of $1.25 million, the Company accesses the storm fund on average 4.5 times per year (i.e., 25 storms over a five and one half year period) (Attorney General Brief at 98, citing Exh. DPU-AG-1-19; Attorney General Reply Brief at 56).[43] Thus, she claims that many storms considered by the Company to be "major" are actually more likely to be "routine" (Attorney General Brief at 98, citing Exh. AG-DO-CF-Rebuttal-1, at 3-4; Attorney General Reply Brief at 56). The Attorney General asserts that increasing the threshold to $2.4 million likely would reduce storm fund access to, on average, 2.7 times per year and ensure that only those events that clearly fall outside of normal risk built into rates would be eligible for storm fund recovery (Attorney General Brief at 98, citing Exh. AG-1-19; Attorney General Reply Brief at 56-57).

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[43] The Attorney General's five and one half year period appears to be 2010 to the end of the test year in this case (Exh. DPU-AG-1-19 & Att.)

Second, the Attorney General argues that the amount collected annually through base rates and designated to the storm fund should increase from $4.3 million to $4.8 million (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50; Attorney General Reply Brief at 53 n.21). In this regard, she contends that if the storm fund threshold had been $2.4 million rather than $1.25 million, and if the five costliest storms of the 25 storms at issue were excluded from consideration,[44] only 15 storms would have qualified for storm fund cost recovery (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29). According to the Attorney General, the annualized amount of the net incremental O&M expense associated with these 15 storms was $4,766,284, thereby justifying the recommended representative level of $4.8 million (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50).

Third, the Attorney General argues that the carrying charge applied to any unrecovered balance in the storm fund should be set at the customer deposit rate and not the WACC (Attorney General Brief at 98; Attorney General Reply Brief at 53).[45] According to the Attorney General, the application of the WACC to deferred storm fund-eligible costs has permitted the Company to recover $81 million in interest between 2010 and 2015 (Attorney General Brief at 98, citing Exhs. NG-RRP-6b, at 2; AG-DO-CF-1, at 27-28; Attorney General Reply Brief at 54). Further, the Attorney General contends that the application of the WACC to deferred storm

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44 These five storms are: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; (3) Nor'easter Nemo in February 2013; (4) Hurricane Sandy in October 2012; and (5) Blizzard Juno in January 2015 (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29).

45 The Company's current pre-tax WACC is 11.48 percent (Exh. NG-RRP-6a). The Company's customer deposit rate is 0.69 percent, which is equivalent to the average rate paid on two-year United States Treasury notes for the twelve months ended December 31, 2015, as stated in the Federal Reserve Statistical Release.

fund-eligible costs has led to considerable risk and cost inappropriately being transferred to ratepayers (Attorney General Brief at 98; Attorney General Reply Brief at 54). Thus, she asserts that to avoid this risk transfer, and because she argues that the deferral of storm costs is short-term, the Department should adopt the customer deposit rate as the appropriate carrying charge (Attorney General Brief at 98-99; Attorney General Reply Brief at 54-55).[46]

2. PowerOptions

PowerOptions argues that the Company's storm fund must be carefully examined and that preparing for storms, and properly repairing the distribution system after storms, are part of "doing business" in New England (PowerOptions Reply Brief at 11). Further, PowerOptions contends that if the Company's storm fund is continued, the Department should adopt the Attorney General's recommendations to raise the cost-per-storm threshold to access the storm fund from $1.25 million to $2.4 million (PowerOptions Reply Brief at 11). PowerOptions agrees with the Attorney General that increasing the threshold likely will reduce the number of storms that qualify for storm fund recovery and ensure that only those larger-scale storm events that clearly fall outside of normal risk built into rates would be eligible for such recovery (PowerOptions Reply Brief at 11).

3. Company

National Grid asserts that the storm fund should continue, and the Company rejects the various arguments raised by the Attorney General in support of terminating the fund (Company Brief at 183-189). In particular, the Company argues that the storm fund provides a necessary

[46] The Attorney General states that if the Department raises the cost-per-storm threshold to $2.4 million and if the customer deposit rate is used to accrue carrying charges on the deficit, the $20 million cap on the fund balance "will likely suffice" (Exh. AG-DO-CF-1, at 29).

means of cost recovery that appropriately correlates to the strict requirements imposed on electric companies for immediate and unqualified response to storms (Company Brief at 183-184). In this regard, the Company contends that there is no feasible manner by which the magnitude of storm costs now incurred simply could be deferred for later recovery in a future rate case, and that annual rate cases would be necessary to achieve a level of recovery that would satisfy the Company's rating agencies (Company Brief at 184, 187). National Grid asserts that such an outcome would be detrimental to ratepayers and the financial integrity of the Company (Company Brief at 184).

The Company proposes to maintain the $1.25 million threshold that currently applies to determine eligibility for storm fund recovery (Company Brief at 179). The Company rejects the Attorney General's recommendation to increase the cost-per-storm threshold to access the storm fund from $1.25 million to $2.4 million (Company Brief at 189). According to the Company, the Attorney General's recommended threshold is not based on any analysis whatsoever, but is simply a "mathematical computation to back into a recommendation concluding that only two storms a year should qualify" (Company Brief at 190-191). Conversely, the Company contends that the $1.25 million is set at a point that draws a distinct line between events that require a response using resources that are contemplated in base rates and those events that involve costs that are not included in base rates, which are largely related to the costs of external crew complements called into pre-stage for relatively larger impact events (Company Brief at 191). Further, the Company notes that between 2010 and 2015, there were 240 discrete storm events that caused the Company to incur incremental repair and restoration costs, but only 25 of these events (or approximately ten percent) qualified for storm fund recovery (Company Brief at 190, 192, citing Exh. NG-RRP-1, at 66-68). Thus, the Company asserts that the $1.25 million threshold is appropriate (Company Brief at 192). However, the Company notes that in the event the Department does raise the threshold, a corresponding increase in base rates is necessary to fund storm costs for those storms that would not meet the threshold (Company Brief at 191-192; Company Reply Brief at 74).[47]

With respect to National Grid's proposal to increase the annual base rate contribution to the storm fund to $14.0 million, the Company argues that the current annual contribution of $4.3 million is not sufficient because the number of qualifying events is increasing due to prevailing weather patterns and the strict emergency response requirements placed on the Company by Massachusetts law and the Department's regulations (Company Brief at 179-180, citing Exh. DPU-32-10). Further, the Company argues that if the Department does not increase the current amount of $4.3 million collected annually through base rates and contributed to the storm fund, there will continue to be a relatively greater need to defer and delay storm-cost recovery (Company Reply Brief at 74).

Next, National Grid argues that its proposal with respect to carrying costs is designed to more equitably share with ratepayers the risk related to major storms (Company Brief at 180, citing Exh. NG-RRP-1, at 87-88). National Grid contends that it cannot defer hundreds of millions of dollars for multiple years, with another five years or more needed for recovery,

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[47] The Company maintains that large storm costs are not appropriate for the "ebb and flow" of base ratemaking treatment because: (1) it is not possible to reasonably identify a "representative" level of major storm events; and (2) as the threshold increases, there is an increase in the "win or loss" that occurs for the ratepayers and Company (Company Brief at 192). However, the Company argues that if the threshold is set at $2.4 million, as recommended by the Attorney General, the Department should increase base rates by $5.2 million (Company Reply Brief at 74, citing Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46).

without recovery of adequate carrying costs (Company Reply Brief at 74). Thus, the Company asserts that any changes to the storm fund that build in delay and deferral must be accompanied by adequate carrying costs (Company Reply Brief at 74).

Finally, the Company argues that its symmetrical cap proposal is designed to protect against substantial accumulation of fund balances creating an oversized surplus or potentially harmful deficit (Company Brief at 181, citing Exh. DPU-21-18). The Company contends that given recent qualifying storm events, an increase in the symmetrical cap on the fund balance from $20 million to $30 million is a necessary change to minimize the potential for frequent rate changes, to accommodate the greater level of annual customer contribution proposed in this case, and to provide for more stable rates for customers (Company Brief at 181, citing Exhs. NG-RRP-1, at 89; DPU-21-18). Thus, according to the Company, the proposed symmetrical cap and the base distribution rate contribution are intended to work in conjunction with one another to establish rate stability for customers (Company Brief at 181).

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to levelize storm restoration costs of major storms on ratepayers. D.P.U. 13-90, at 13, citing D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. However, the Department has recognized that recent experience, both with National Grid and other electric utilities, has demonstrated 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

Since the Company's last rate case, 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 C.M.R. § 19.03 (setting forth standards for the acceptable performance for emergency preparation and restoration of service for electric and gas companies); Investigation by the Department of Public Utilities into the Storm Preparation and Response of Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-85-A/11-119-A at 153 (2012) (imposing penalties for Company's failure to restore service to its customers in a safe and reasonably prompt manner). In order 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 the Company 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., Exh. DPU-32-4, Att. (25 major storms since 2009)). Not surprisingly, the costs of responding to those events to restore power for customers in an expeditious fashion have increased as well.

We acknowledge that National Grid's current storm fund mechanism has not provided the desired balance between cost recovery and rate stability. In particular, the overall number of major storms in the past six and a half years contributed to a large storm fund deficit that expanded even further due to the accumulation of a significant amount in carrying charges. The number of these storms themselves could not have been anticipated when the storm fund mechanism was developed for the Company, although we have certainly seen a trending to more severe storms over the past several years than previously experienced. As a result, without a storm fund mechanism it is unlikely that during this time frame the Company could have absorbed these costs without filing a base rate case, or even multiple rate cases, which could have resulted in an increase in rates to ratepayers for other costs.

Therefore, we find that if properly structured, the Company's storm fund can provide for adequate recovery of storm costs from customers in a manner that is designed to create rate stability. On that basis we conclude that the storm fund shall continue, but with several important modifications, as discussed below.[48]

3. Modifications to the Storm Fund

a. Cost-Per-Storm Threshold

Currently, for any storm for which National Grid incurs more than $1.25 million in costs, the Company is permitted to access the storm fund for reimbursement of only that portion of the costs that exceed $1.25 million. D.P.U. 09-39, at 207. The Company's current threshold of $1.25 million per storm was first established in the D.T.E. 99-47 Settlement and was maintained following the Department's adjudication of the proposed modifications to the storm fund in D.P.U. 09-39. It stands to reason that per-storm restoration costs have increased since 2009. Thus, we find that it is appropriate to increase the cost-per-storm threshold to reflect the general

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48 Further, we note that pursuant to § 94, the Company must file its next base rate case within five years. At that time, the Department will have another opportunity to review the modified storm fund and determine whether it should continue even further.

increase in costs and to prevent the inclusion in the storm fund of future storm events of a more routine nature.

The Attorney General recommends that the cost-per-storm threshold should be increased to $2.4 million to better reflect the frequency of "truly" major storms (Attorney General Brief at 98, citing Exh. DPU-AG-1-19; Attorney General Reply Brief at 56-57). The Company did not propose an increase to the cost-per-storm threshold, but argues that any such increase must come with a corresponding increase to the amount collected through base rates to address smaller storms that do not qualify for storm fund recovery (Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46).[49]

The Department has considered the arguments and has reviewed the record concerning the cost-per-storm threshold (Exhs. NG-RRP-Rebuttal-1, at 9-10; NG-DEB-Rebuttal-1, at 3-7; AG-DO-CF-1, at 28; AG-DO-CF-Rebuttal-1, at 4-5; DPU-21-18; DPU-32-2; AG-6-1; DPU-AG-1-19 & Att.; Tr. 15, at 1633-1649, 1670-1676, 1680-1681; RR-DPU-46; RR-DPU-51). The Department finds that it is appropriate to increase the threshold to account for the effect of inflation on costs during this period. Absent an inflation adjustment to the current threshold to bring incremental O&M service restoration costs to present value terms, the cost of a storm in 2009 (in present value dollars) would be less than the cost of that same storm in 2015. Therefore, the Department finds that the threshold should be increased by inflation based on the gross domestic product price index ("GDP-PI") from the U.S. Bureau of Economic Analysis for the period between 2009 and June 30, 2015, which would increase the current $1.25 million

[49] The Company collects through base rates (1) an annual amount for contribution to the storm fund reserve, and (2) an annual amount to cover costs up to the cost-per-storm threshold and for smaller storm events that do not qualify for the storm fund.

threshold by approximately ten percent to approximately $1.5 million.[50] We find that this increased cost-per-storm threshold provides an appropriate balance between providing the Company 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.

Further, we find that the increase in the cost-per-storm threshold applicable to the storm fund also necessitates changes in the amount the Company collects through base rates to (1) contribute to the storm fund, and (2) recover O&M costs up to the $1.5 million threshold for storms that qualify for the storm fund, as well as costs associated with smaller storm events that no longer qualify for storm fund recovery. These issues are discussed in the next section.

b. Amounts Collected through Base Rates

i. Annual Contribution to the Storm Fund

National Grid's current $4.3 million annual base rate contribution to the storm fund was established in the Company's last rate case. D.P.U 09-39, at 207. The Company proposes to increase the annual base rate contribution to the storm fund by $9.7 million to $14.0 million (Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 4, 26 (Rev. 3)). The Company argues that the current annual contribution of $4.3 million is not sufficient because the number of qualifying events is increasing due to prevailing weather patterns and increased costs associated with the strict emergency response requirements placed on the Company by Massachusetts law and the Department's regulations (Company Brief at 179-180, citing Exh. DPU-32-10). Conversely, the Attorney General argues that a $500,000 increase of the annual contribution to $4.8 million is

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50 GDP-PI sourced from U.S. Bureau of Economic Analysis http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=1&904=2015&903=4&906=q&905=2016&910=x&911=0 (see also Exh. WP-NG-RRP-16).

more appropriate (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50; Attorney General Reply Brief at 53 n.21).

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 rate contribution amount of $4.3 million has proven to be insufficient to maintain rate stability. See, e.g., 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 million in storm costs over a three-year period). Thus, we conclude that an increase to the annual base rate contribution to the storm fund is warranted.

In this regard, the Department strives to set a new annual contribution amount that would permit the Company to recover storm costs over time without generating a surplus or deficit balance in the storm fund that would exceed the symmetrical cap.[51] 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. However, 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.

[51] The symmetrical cap is discussed in further detail below.

The Department has reviewed the record supporting the positions advanced by the Company and the Attorney General (e.g., Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 26 (Rev. 3); NG-RRP-Rebuttal-1, at 10-11; AG-DO-CF-1, at 29; DPU-21-18; DPU-23-2; DPU-32-1; DPU-32-4, Att.; DPU-32-10; DPU-32-16; DPU-AG-1-19, Att.). Further, the Department has considered the number of major storms that have occurred between the Company's last rate case and the end of the test year; the incremental costs of these storms; the number of storms with incremental costs so high that they should be deemed statistical outliers; and the number of storms that would not have been eligible for storm fund recovery if the cost-per-storm threshold was $1.5 million (Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.). Based on these considerations and our review of the record, we find that setting the annual base rate funding at $10.5 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. We find that neither the Company's proposal nor the Attorney General's recommendation achieves an appropriate balance. Therefore, we decline to adopt the Company's proposal or the Attorney General's recommendation.

As noted above, the Company proposes to increase the $4.3 million annual base rate contribution to the storm fund by $9.7 million for a total of $14.0 million (Exhs. NG-RRP-1, at 69, 85 86; NG-RRP-2, at 4, 26 (Rev. 3)). The Department finds that the appropriate level of O&M expense is $10.5 million, which represents an increase of $6.2 million over the test year amount. Accordingly, the Department will reduce the Company's proposed cost of service by $3.5 million ($9.7 million less $6.2 million).

ii. Annual O&M Expense

As noted above, the Company argues that if the Department increases the cost-per-storm threshold to access the storm fund, an increase in the test year amount collected through base rates is warranted (Company Reply Brief at 6 n.4, 74, citing Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46; see also Tr. 8, at 1318-1319). During the test year, the Company experienced six major storms that would qualify for storm fund recovery (Exh. DPU-32-4, Att.; Tr. 8, at 1318-1319; RR-DPU-46, Att.). Thus, built into test year O&M is $7.5 million, representing the threshold amount for each storm (i.e., $1.25 million x six major storms) (Tr. 8, at 1318-1319). The Attorney General does not specifically address this issue.

Given that the frequency of storms events varies significantly each year, the test year level of O&M costs associated with storms events may not be representative of the Company's future costs. Therefore, we find that it is appropriate to normalize the level of base rate recovery to derive a more representative amount of O&M expense associated with storm events. This evaluation results in approximately three storms per year qualifying for storm fund recovery (18 storms/6.5 years).[52] Applying a $1.5 million cost-per-storm threshold to each of the three storms yields $4.5 million in O&M costs to be recovered in base rates. This amount is $3.0 million less than the $7.5 million the Company recovered in the test year at the $1.25 million threshold. Further, the Department finds that it is appropriate to include in O&M expense the costs associated with one test year storm (a wind/rain storm in July 2014) that would

52 Between 2009 and the end of the test year, the four costliest storms were: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; (3) Hurricane Sandy in October 2012; and (4) Nor'easter Nemo in February 2013 (Exh. DPU-32-4, Att.). The additional three storms excluded from consideration were: (1) Hurricane Earl in September 2010; (2) a wind/snow storm in November 2013; and (3) a wind/rain storm in July 2014 (Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.).

not have qualified for storm fund recovery under the $1.5 million threshold and, therefore, would be subject to base rate recovery (see Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.; see also n.52 above). The cost associated with this one storm (net of Verizon New England, Inc. ("Verizon") billings)[53] is $1,396,743 (RR-DPU-46 & Att.).

As noted, the Company's test year level of O&M expense includes $7.5 million associated with six major storms. The Department has determined that the appropriate level of O&M expense is $5,896,743 ($4,500,000 + $1,396,743). Accordingly, the Department will reduce the Company's proposed cost of service by $1,603,257 ($7,500,000 less $5,896,743).

c. Storm Fund Cap

In the Company's last rate case, the Department determined that to limit the balance in the storm fund that may be used to recover incremental costs from major storms and to prevent the fund from having a deficit balance that is excessive, it was appropriate for the storm fund to have a symmetrical cap (positive and negative) of $20 million. D.P.U. 09-39, at 208. We find that it remains appropriate for the storm fund to continue to have a symmetrical cap on the storm fund balance.

The Company proposes to increase the storm fund's symmetrical cap from $20 million to $30 million to coincide with its proposed increase in the annual base rate contribution for storm costs (Exhs. NG-RRP-1, at 88-89). The Company contends that given recent qualifying storm events, an increase in the symmetrical cap from $20 million to $30 million is a necessary change in order to minimize the potential for frequent rate changes, accommodate the greater level of

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53 Because of joint ownership of certain facilities, Verizon and the Company share in the cost of storm restoration work. See Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 11-56, at 6 n.9 (2013); D.P.U. 09-39, at 212-213 & n.122.

annual customer contribution proposed in this case, and provide more stable rates for customers (Company Brief at 181, citing Exh. NG-RRP-1, at 89; DPU-21-18). The Attorney General states that if the Department raises the cost-per-storm threshold to $2.4 million and if the customer deposit rate is used to accrue carrying charges on the deficit, the $20 million cap "will likely suffice" (Exh. AG-DO-CF-1, at 29).

In an effort to minimize the potential for frequent rate changes (either positive or negative) and to realign the risks associated with storm cost recovery to protect ratepayers' interests, the Department finds that a symmetrical cap of $30 million on the storm fund balance is appropriate. Further, in order to prevent the storm fund from falling into a significant deficit as the result of a single major storm event, we find that it is necessary to exclude from storm fund eligibility any single storm event that exceeds $30 million in incremental costs (exclusive of Verizon costs). The Company may seek to defer these costs for recovery in its next base rate case. We recognize that given the recent history of storm events, this change to the storm fund mechanism could trigger the filing of a base rate case if multiple storms of a significant magnitude occur during the period in between base rate case filings. However, we find that excluding storms that exceed $30 million in incremental costs, in conjunction with the other modifications approved in this Order, will provide necessary rate stability for customers and help ensure that the storm fund works as intended.

d. Carrying Costs on the Storm Fund Balance

The Company's current storm fund balance accrues interest at the pre-tax WACC, which is 11.48 percent (Exh. NG-RRP-6a at 1). See also D.P.U. 09-39, at 207-208; D.P.U. 09-39-A, at 38. As noted above, the objective of a storm fund is to levelize the cost recovery for major storms on distribution rates. The use of a storm fund is not intended to shift the financial risk of paying for major storms from electric distribution companies to ratepayers. D.P.U. 09-39, at 205; D.P.U. 10-70, at 200. Rather, it is the Company's allowed ROE that is designed, in part, to recognize these business risks. D.P.U. 09-39, at 205; D.P.U. 10-70, at 200; D.P.U. 1720, at 88-89. Since 2009, the Company has accrued approximately $81 million in interest associated with the costs of the 25 major storms that have qualified for the storm fund (Exh. NG-RRP-6b at 2). We find that a continuation of this result would inappropriately overcompensate the Company for its costs of carrying the storm fund costs. Therefore, the interest rate must be modified.

As noted above, the Company proposes that interest will accrue on incremental storm costs when such costs are filed for recovery with the Department (as opposed to when these costs are incurred) (Exh. NG-RRP-1, at 87). The Company proposes that interest accrue on the combination of the storm fund reserve and the costs related to the storms beginning when filed for storm fund cost recovery (Exh. NG-RRP-1, at 88). If the storm fund balance is in a surplus, then the Company proposes that interest will accrue at a carrying charge rate equivalent to the Company's pre-tax WACC, as determined by the Department (Exh. NG-RRP-1, at 87). Conversely, if the combined storm fund balance is in a deficit, then the amount in deficit (up to the $30 million cap) would accrue interest at the Company's customer deposit rate (Exh. NG-RRP-1, at 88). Further, any storm fund deficit in excess of the proposed $30 million storm cap would accrue interest at a carrying charge rate equivalent to the pre-tax WACC (Exh. NG-RRP-1, at 88).

We find that the Company's proposal for carrying charges to accrue on incremental storm costs when such costs are filed for recovery with the Department will reduce the interest costs paid by ratepayers, and likely will encourage the Company to expedite its filing for cost recovery. Thus, we approve this aspect of the Company's proposal. However, we are not persuaded that the remaining proposed modifications are sufficient to ensure that the carrying costs associated with major storms are appropriately determined. Rather, in order to properly reflect the cost of this balance, the Department finds that the prime rate is a more reasonable carrying charge to be applied to storm fund balances, irrespective of whether the balance represents a surplus or deficit. Accordingly, the Department modifies the carrying charge component of the Company's storm fund. The Company's storm fund shall accrue interest on the combination of the storm fund balance and the costs related to the storms filed for storm fund cost recovery. The interest rate shall be the prime rate,[54] irrespective of whether the storm fund balance represents a surplus or a deficit.

e. Extension of the SFRF and Transfer of the Current Storm Fund Balance

As noted above, in a separate proceeding, the Department extended the SFRF to June 2018 in order to continue collection of the current storm fund balance. D.P.U. 13-85, at 105. National Grid proposes to extend the SFRF an additional 14 months to August 2019, in order to replenish the existing storm fund to account for the nine additional qualifying storm costs that took place after the Company's filing in D.P.U. 13-85, and to minimize the carrying cost associated with those storms (Exhs. NG-RRP-1, at 68-69, 78). Further, the Company proposes to transfer the deficit balance to be collected through the SFRF to a separate regulatory

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54 The prime rate calculated in accordance with 220 C.M.R. § 6.08(2).

asset, and to reset the storm fund balance to zero (Exh. NG-RRP-1, at 78). In addition, the Company proposes that any residual balance (either positive or negative) remaining in the regulatory asset at the end of the extended recovery period (i.e., August 2019) then would be transferred to the Company's storm fund (Exh. NG-RRP-1, at 78-79). Finally, the Company proposes that the regulatory asset continue to accrue interest at the pre-tax WACC (Exh. DPU-21-12, at 1). No parties addressed these matters on brief.

The storm fund mechanism, as modified in the instant case, will be applicable to storms occurring after the date of this Order. Therefore, we find that the Company's proposal to transfer the balance associated with the current storm fund balance to a separate regulatory asset and extend the SFRF an additional 14 months to continue to collecting that balance is reasonable and appropriate. Further, the record demonstrates that under the Company's proposal, customers would benefit from a reduction in carrying charges as a result of extending the SFRF through August 2019 (Exh. DPU-18-2). The Company estimates the reduction of interest at approximately $19.7 million (Exh. DPU-18-2). Additionally, we find it appropriate to transfer any residual balance to the storm fund at the end of the extended recovery period. Based on these considerations, we approve the Company's proposal.

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 the date of this Order.

The current storm balance shall be recovered through August 2019 consistent with the findings above. Further, consistent with the Department's findings in D.P.U. 13-85, at 105, the

Department directs the Company to file as part of its compliance filing in this case a revised Storm Fund Replenishment Provision tariff to replace M.D.P.U. 1292.

Finally, consistent with the findings above, the Department has reduced the Company's proposed cost of service by (1) $3.5 million relative to the annual base rate contribution to the storm fund, and (2) $1,603,257 relative to the annual amount in base rates to cover costs up to the cost-per-storm threshold and for smaller storm events that do not qualify for the storm fund. These reductions are shown as combined adjustments on the Department's Schedules.

VII. RATE BASE

A. Overview

The Company's test year rate base was $1,760,316,969, based on a total net utility plant in service of $4,084,097,215 (Exh. NG-RRP-2, at 30 (Rev. 3)). To this amount, the Company proposes to add $39,210,328 in rate base adjustments for a total proposed rate base of $1,799,527,297 (Exh. NG-RRP-2, at 30 (Rev. 3)). The Company's total proposed rate base consists of: $2,307,263,848 in net utility plant in service, $23,231,040 in net materials and supplies, and $68,019,916 in cash working capital; less, $569,147,565 in deferred income taxes and $29,839,942 in customer deposits (Exh. NG-RRP-2, at 30 (Rev. 3)).[55]

B. Plant Additions

1. Introduction

In D.P.U. 09-39, the Department approved the current CapEx mechanism, which allows recovery of the revenue requirement associated with the Company's annual capital expenditures, net of the amount recovered in base rates through depreciation expense. D.P.U. 09-39, at 79, 82.

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

The Department capped the amount of capital spending the Company could recover through the CapEx mechanism based on an annual investment of $170 million. D.P.U. 09-39, at 82.[56] Pursuant to D.P.U. 09-39, the Company files a Capital Investment Report ("CapEx filing") by July 1st of each year containing information and project documentation relating to the capital placed in service during the prior calendar year ("CY"). D.P.U. 09-39, at 85. By November 1st of the filing year, the Company must file its CapEx factors that incorporate the costs associated with the capital placed in service, up to the allowed cap, into a rate adjustment effective March 1st of the following year. D.P.U. 09-39, at 85.

From 2010 through 2015, National Grid made annual CapEx filings and proposed annual CapEx factors to recover capital additions made in 2009 through 2014, up to the allowed cap. The Company's annual CapEx filings were docketed as D.P.U. 10-79 (2009 CY additions), D.P.U. 11-60 (CY 2010 additions), D.P.U. 12-48 (CY 2011 additions); D.P.U. 13-84 (CY 2012 additions), D.P.U. 14-95 (CY 2013 additions), and D.P.U. 15-84 (CY 2014 additions). The Company's CapEx mechanism is a component of the Company's RDM tariff and, therefore, the CapEx factors were filed as part of the Company's RDM filings.[57]

During the pendency of the first CapEx filing, D.P.U. 10-79, the Attorney General, pursuant to G.L. c. 25, § 5, requested an independent audit of the Company's record keeping,

[56] While the Department limited the Company's allowed recovery under CapEx mechanism to $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 recover through its CapEx mechanism, the Company could seek to include such investment in rate base in its next base rate proceeding. D.P.U. 09-39, at 82-83.

[57] The RDM filings were docketed as D.P.U. 10-152, D.P.U. 11-117, D.P.U. 12-115, D.P.U. 13-175, D.P.U. 14-136, and D.P.U. 15-154.

accounting practices, and process for developing the filing, which was docketed and commenced in D.P.U. 11-18. Audit of National Grid's Calendar Year 2009 Capital Investment Program, D.P.U. 11-18-F at 1 (2016). The Department allowed the Company to recover its proposed revenue requirement through the CapEx factors, subject to further investigation, and placed the prudency review in D.P.U. 10-79 on hold during the pendency of the audit. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-152, at 5 (2011); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-79, Interlocutory Order on Filing Requirements at 5-7 (June 14, 2011) ("D.P.U. 10-79 Interlocutory Order"). In light of the concerns giving rise to the Attorney General's audit request, the Department also issued filing guidelines for future CapEx filings to be made during the pendency of the audit. D.P.U. 10-79 Interlocutory Order at 5-7. The audit was completed in 2015 and the Department issued a final Order accepting the final audit report on February 26, 2016. D.P.U. 11-18-F.[58] Consistent with the process for D.P.U. 10-79, the Department allowed the Company to recover its proposed revenue requirement, subject to further investigation, through the CapEx factors[59] for each subsequent year that the audit was pending, but placed the prudency review of all capital

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58 The auditor found an adjustment of $1.2 million, which the Department directed the Company to correct in this proceeding. D.P.U. 11-18-F, at 15.

59 As noted above, the CapEx factors were filed as part of the following RDM filings: Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-117, at 2 (2012); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 12-115, at 3 (2013); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-175, at 4 (2014); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136, at 3 (2015); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-154, at 4 (2016).

investments on hold during the pendency of the audit.[60] In summary, the Department allowed the Company to recover its proposed revenue requirements associated with the capital additions made from 2009 through 2014 subject to further investigation, but did not fully adjudicate the CapEx filings, made no findings that the associated capital additions were prudent and used and useful, and did not issue any final Orders while the audit was pending. Thus, the Company, in this rate case, seeks a determination of the prudence and used and usefulness of the capital additions that were the subject of the annual CapEx filings for investment years 2009 through 2014, plus any capital additions during those years that exceeded the $170 million cap, as well as capital additions placed in service in the first six months of 2015 (the second-half of the test year in this proceeding), in order for those additions to be included in rate base (Exh. NG-JHP-1, at 13-14).[61]

2. Investment Activity

From January 1, 2009 through June 30, 2015, National Grid completed $1,189,550,456 in plant additions and incurred $93,778,658 in cost of removal, which resulted in an increase in utility plant of $1,283,329,114 (Exhs. DPU-10-6, Att.; AG-7-5, Att.; RR-DPU-12; RR-DPU-13, Att.).[62] National Grid identified 1418 capital projects that were completed during this period

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60 The following CapEx dockets were placed on hold: D.P.U. 11-60; D.P.U. 12-48; D.P.U. 13-84; D.P.U. 14-95; D.P.U. 15-84.

61 In the absence of the CapEx mechanism, the Company would have sought inclusion in rate base of all capital additions placed in service since its last rate case, which is effectively what the Company seeks now because the CapEx filings were not fully adjudicated.

62 The Company's investment activity is broken down as follows: (1) $463,986,528 for 62 blanket projects; (2) $217,111,440 for 100 program projects; (3) $509,652,488 for 1,253 specific projects; and (4) a $1,200,000 negative adjustment to reflect an error for a double

(Exhs. DPU-7-23, Att. (Rev.); DPU-7-23, Att. (Supp.); RR-DPU-12). National Grid groups its capital projects into three categories: (1) specific projects, (2) blanket projects, and (3) program (or other annual) projects (Exh. NG-JHP-4, at 1). As part of its initial filing in this case, the Company provided the filings made in each of the previous CapEx dockets as well as documentation relating to the first six months of 2015. For each project the Company seeks to include in rate base, the Company also provided a spreadsheet 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-7-23, Att. (Rev.)). As discussed below, the Attorney General challenges the sufficiency of the documentation provided for 20 specific projects, two storm program projects, 32 blanket projects, and 47 program projects (Attorney General Brief at 12-19).

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;[63] (3) documentation relating to the approved amounts (such as walk-in

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charge to the Company for the cost of materials associated with a limited subset of capital work that was subcontracted out to third parties in 2009 through 2012 (RR-DPU-12).

63 Screen-prints may also be from older systems including PowerPlant and Primavera Portfolio Management (Exh. NG-JHP-4, at 3).

documents, re-approval forms, distribution capital investment group papers,[64] United States Sanctioning Committee ("USSC")[65] sanction papers, 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 asset 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., Exhs. NG-JHP-3; NG-JHP-4). For blanket and program projects the Company also provided a fiscal year variance analysis report and a fiscal year closure paper (Exh. NG-JHP-4, at 12, 13).[66]

4. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that the Company failed to provide clear and reviewable documentation demonstrating the prudence of its capital additions for $56 million in variances

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64 This group is an executive management group that approves projects with projected scope and costs above established thresholds (Exh. NG-JHP-3(a) at 12 (prefiled testimony)).

65 The USSC is a group within National Grid USA that provides executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization (RR-DPU-43, Att. 3, at 17).

66 As described more fully below, the Company did not initially provide blanket project closure papers for fiscal years 2013 and 2014. Further, the Company initially did not provide closure papers for six program projects over $1 million or reauthorization forms for 14 program projects over $100,000.

(Attorney General Brief at 11, Attorney General Reply Brief at 12).[67] Specifically, the Attorney General contends that the Company failed to provide: (1) adequate explanations for 20 specific projects that had cost variances totaling $6.5 million; (2) adequate variance explanations for two storm capital program projects,[68] with cost variances totaling $11.7 million; and (3) closing papers and documentation for 31 blanket and 47 program projects with unfavorable cost variances totaling $37.8 million (Attorney General Brief at 11, 14, 19; Attorney General Reply Brief at 12). Therefore, the Attorney General claims that the Department should exclude $56 million from the Company's rate base because it did not meet its burden of demonstrating the propriety of these additions to rate base (Attorney General Brief at 11; Attorney General Reply Brief at 6). The Attorney General asserts that the Company bears the burden of demonstrating the propriety of additions to rate base through clear and cohesive reviewable evidence and cannot simply provide a "cascade" of documents and point to the overall volume as evidence of prudence (Attorney General Reply Brief at 8, citing D.P.U. 14-150, at 42–43 (2015)).

Further, the Attorney General challenges the Company's claims that its capital budgeting and authorization processes is evidence of "reasonable mechanisms to control costs and manage

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67 In her initial brief, the Attorney General sought disallowance of $68.6 million that included $50.4 million in blanket and program costs. The $50.4 million amount included 27 program projects, or $18.2 million, and 32 blanket projects, or $32.2 million (Attorney General Brief at 11-19). On reply, the Attorney General reduced this amount by $12.6 million, the amount of one blanket project (CBS0004), due to an accounting error that the Company corrected (Attorney General Reply Brief at 6, citing Company Brief at 123).

68 On brief the Attorney General and the Company both refer to the storm projects as storm capital "blanket" projects, but these storm projects appear on the Company's list of program projects and in the program project variance analysis reports (see, e.g., Exhs. DPU-7-23, Att. (Supp.); NG-JHP-3(e), JLG-8, at PGRM-1190). Hereinafter, we refer to these storm projects as program, not blanket, projects.

projects within established budget parameters" with respect to blanket and program projects because the Company did not follow its own procedures for cost management and control (Attorney General Reply Brief at 7, citing Company Brief at 119). Specifically, with respect to blanket projects the Attorney General contends that the Company did not prepare closure papers at the end of the fiscal year ("FY"), upon the actual closure of those projects in FYs 2013 and 2014 (Attorney General Reply Brief at 8, citing Company Brief at 118). Instead, the Attorney General claims that the Company created the documentation years after the closure of the projects, on April 26, 2016, following multiple requests by the Department and the Attorney General for their production (Attorney General Reply Brief at 8, citing Exhs. DPU-20-1 through DPU-20-82; DPU-20-31 (Supp.); DPU-20-35 (Supp.); AG-21-1). Similarly, the Attorney General argues that the Company did not complete closure papers and/or final cost documentation for program projects in FYs 2013 and 2014, as well as for several projects in fiscal year 2015, until after the close of the evidentiary hearings in this proceeding (Attorney General Reply Brief at 8, citing Exh. NG-JHP-Rebuttal-1, at 20; Tr. 3, at 435–36). The Attorney General, therefore, asserts that the timing of the completion of this documentation calls into question the efficacy of the Company's process to control costs and, moreover, the prudency of the Company's capital expenditures related to these blanket and program projects (Attorney General Reply Brief at 8).

ii. Specific Projects

The Attorney General argues that the Department should exclude $6.5 million in variance amounts relating to 20 specific projects for which the Company did not provide variance explanations (Attorney General Brief at 11-12).[69] The Attorney General contends that the Department specifically sought information relating to the cost over-runs, but that the Company did not provide any explanations (Attorney General Brief at 11-12). Instead, the Attorney General claims that the Company simply cited to its own internal policies to: (1) provide a variance explanation only when project costs differ by more than ten percent; and (2) consider only the combined variance of projects managed as part of the same effort, rather than to provide the variances associated with each project (Attorney General Brief at 13-14). The Attorney General asserts that the Company's reliance on its internal policies is insufficient because the Department has specifically held that "a company's internal project cost estimation policies cannot . . . override, the company's obligation to demonstrate to the Department the prudence of its capital project costs" (Attorney General Brief at 14, citing D.P.U. 14-150, at 87). The Attorney General, therefore, recommends that the Department exclude $6.5 million from rate base because the Company failed to carry its burden of production with respect to these cost variances (Attorney General Brief at 14, citing D.T.E. 03-40, at 52, n.31; D.T.E. 01-56-A at 16).

iii. Storm Capital Programs

The Attorney General argues that the Department should disallow $11.7 million in cost variances related to two storm programs because the Company failed to provide an explanation for the cost variances that occurred during FYs 2010 and 2012 (Attorney General Brief at 19, citing Exhs. DPU-19-1; DPU-19-2). The first program includes two FY 2010 projects, C014821

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[69] These projects include: C008666; C005339; C014549; C023591; C036385; C028886; C002364; C002388; C012018; C012502; C024120; C005342; CD01253; C001423; C028871; C029104; C031552; CD01174; C031324; C002504 (Attorney General Brief at 12).

and C014822, totaling a $2.4 million variance (Attorney General Brief at 19-20).[70] The second program includes one FY 2012 project, C014821, with a $9.3 million variance (Attorney General Brief at 20). The Attorney General claims that the Company's closure papers do not explain the reason for the cost overruns, and that the Company has evaded any adequate explanation as requested, and required, by the Department (Attorney General Brief at 20). Further, with respect to the FY 2012 variance, the Attorney General asserts that the Department conducted an investigation into the subject storms, found that the Company acted imprudently, and imposed substantial fines (Attorney General Brief at 20, citing D.P.U. 11-85-A/D.P.U. 11-119-A). Further, the Attorney General asserts that although the Company could not predict restoration costs, it should "honor the spirit of its own processes," which contemplate that variance analyses can contribute to "lessons learned" (Attorney General Reply Brief at 10-11, n.6, citing Company Brief at 118-119). The Attorney General, therefore, recommends that the Department exclude from rate base the $11.7 million variance for these storm program projects (Attorney General Brief at 20).

iv. Blanket & Program Projects

The Attorney General argues that the Department should exclude from rate base $37.8 million in cost variances, $18.2 million for 47 program projects,[71] and an additional $19.6

70 These projects are titled "BSW Storm Cap Confirm Proj" and "N&G Storm Cap Confirm Proj," respectively.

71 These projects include: C005490; C005500; C005432; C005543; C005563; C006642; C005439; C005441; C005444; C005449; C016492; C005469; C005475; C005480; C059664; C006138; C028147; C032015; C032016; C032018; C033822; C025810; C032270; C032272; CD00017; C025619; C014821; C021594; C022216; C022217; C016120; C016121; C018594; CD00259; C025326; C025813; C027898; C027927;

million for 31 blanket projects[72], because the Company failed to carry its burden to show that these cost variances were prudently incurred (Attorney General Brief at 15). As an initial matter, the Attorney General contends that the Company did not comply with the D.P.U. 10-79 Interlocutory Order, which required the Company to produce as part of its initial filing "project details for capital projects placed in service costing more than $50,000, including the project cover sheet, approved amount, actual cost, cost variance information, and other applicable documentation such as the appropriate number of units associated with the actual capital placed in service, project sanction, re-sanction, and closure papers" (Attorney General Brief at 14, citing D.P.U. 10-79 Interlocutory Order at 7 n.3). Despite this filing requirement, the Attorney General claims the Company failed to provide in its initial filing closure papers for all of the program and blanket projects in FYs 2013 and 2014, as well as several program projects for FY 2015 (Attorney General Brief at 15).

Further, the Attorney General challenges the Company's eventual production of the requisite documentation relating to blanket projects (filed on May 3, 2016) and program projects (filed on June 2, 2016) as untimely (Attorney General Brief at 16-18). With respect to the blanket projects, the Attorney General argues that National Grid failed to provide the aforementioned documentation during discovery and filed them on May 3, 2016, just twelve hours before the Company's plant additions witness was scheduled to testify (Attorney General

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C031398; C031774; C032024; C035584; C049352; C032572; C033764; C033765; CD01258.

72 These projects include: CBN0002; CBN0004; CBN0010; CBN0011; CBN0012; CBN0014; CBN0015; CBN0016; CBN0017; CBN0022; CBS0010; CBS0011; CBS0014; CBS0020; CBS0022; CBW0002; CBW0006; CBW0010; CBW0011; CBW0014; CBW0016; CBW0020; CN00420; CNM0002; CNM0004; CNM0010; CNM0011; CNM0014; CNM0017; CNM0020; CNM0022.

Brief at 18). According to the Attorney General, due to the volume and nature of the documents, she did not have any time to conduct discovery or review the material in order to effectively cross-examine the Company's witness (Attorney General Brief at 18, citing D.P.U. 14-150, at 49; D.P.U. 10-70, at 194 n. 98, 200). Accordingly, the Attorney General recommends that the Department exclude from rate base $19.6 million in blanket projects' variances for which the Company failed to timely file closure papers (Attorney General Brief at 18).

With respect to the program projects, the Attorney General asserts that the closure papers for the program projects in question, if filed at all, were filed late on June 2, 2016 (Attorney General Brief at 16). As discussed in the next section below, the Attorney General moved to strike this documentation from the record, and urged the Department not to consider them (Attorney General Brief at 16). Accordingly, the Attorney General recommends that the Department exclude from rate base $18.2 million in program projects' variances for which the Company failed to timely file closure papers (Attorney General Brief at 16).

The Attorney General rejects any notion that she seeks disallowance of the aforementioned costs because "a piece of paper is missing from the file . . . ." (Attorney General Reply Brief at 9, citing Company Brief at 123). She argues that this mischaracterization trivializes both the Company's management process and the prudency review process conducted by the Department in this rate case (Attorney General Reply Brief at 9, citing Company Brief at 123). The Attorney General contends that she did not target project costs for disallowance because one piece of paper was missing, but because variance amounts were not supported by the documentation that the Company itself claims is used to "note reasons for any overspending during the fiscal year and [detail] the Company's actions to keep overall capital spending within budgeted amounts" (Attorney General Reply Brief at 9, citing Exh. AG-DO-CF-1, at 52–53).

Further, the Attorney General argues that the late filing of the closure papers is not inconsequential, as it relates to the Company's burden to provide, at a minimum, documentation that allows the Department to evaluate the prudence of each of the capital projects, and to make a determination that each project was placed in service during the test year and is used and useful (Attorney General Reply Brief at 9, citing Company Brief at 123; Bay State Gas Company, D.P.U. 13-75, at 105 (2014); Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 8 (2001)).[73]

b. Company

i. Introduction

National Grid argues that the record contains sufficient evidence for the Department to find that the capital additions submitted for approval in this proceeding were prudently incurred and are used and useful in providing service to customers (Company Brief at 113). The Company claims that it provided actual computations and thousands of pages of supporting documentation including: project cover sheets; approved amounts; actual costs; cost variance information' project sanction, re-sanction, and closure papers; and a detailed explanation of the processes that the Company uses to manage both the allocation and cost of capital expenditures

[73] The Attorney General argues that in several instances the Company provided documentation in April, May, or June, after the discovery deadline had passed and testimony had been filed, and, therefore, too late for the Department, the Attorney General, or other intervenors to conduct a thorough and probative evaluation of the contents of the documentation for prudency purposes (Attorney General Reply Brief at 9-10, citing Exhs. NG-JHP-Rebuttal-2 (filed April 19, 2016); DPU-20-31 (Supp.), DPU-20-35 (Supp.) (filed May 3, 2016); NG-JHP-Rebuttal-2 (Supp.) (filed June 2, 2016)).

(Company Brief at 113, citing Exhs. NG-JHP-1, at 9, 21-23; NG-JHP-3; NG-JHP-4; NG-JHP-Rebuttal-2; NG-JHP-Rebuttal-2 (Supp.); DPU-20-31 through 20-53 (Supp.)).

The Company also argues that its capital budgeting and authorization process assures cost containment (Company Brief at 119). The Company contends that it conducts a detailed, multi-tiered capital-planning process to control costs and manage projects within the established budget parameters (Company Brief at 115, citing Exh. NG-JHP-1, at 21-23). Specifically, the Company points to its Delegation of Authority ("DOA") and Sanctioning/Re-sanctioning policies for projects with costs under $1 million and at or above $1 million as reasonable mechanisms to control costs and manage projects within the established budget parameters (Company Brief at 116-118, citing RR-DPU-43, Atts. 2, 3). Further, the Company argues that its Capital Funding Project Overrun Report is the primary vehicle employed for cost-control purposes (Company Brief at 119). According to the Company, this monthly report identifies the funding projects that have exceeded or are forecasted to exceed the authorized DOA amount, after which the responsible individual must complete a written plan to bring the affected funding project within DOA limits within ten days and seek management re-sanction of those funding projects that exceed the authorized spending limit no later than 60 days after notification (Company Brief at 115, 119, citing RR-DPU-43, Atts. 2, 3).

Further, the Company contends that the Attorney General's argument relating to the timing of filing certain documents amounts to form over substance, does not raise a challenge to the prudence or used and usefulness of any capital project, and is insufficient to justify disallowance of $56 million in capital investment costs (Company Brief at 123, 128; Company Reply Brief at 16). The Company contends that there is no requirement for a petitioner to present every piece of paper associated with a project in the initial filing, and that no additional document can be provided during the case or the project is subject to disallowance (Company Brief at 123). Thus, the Company asserts that the Department should not disallow the costs of substantial work projects put in place for the benefit of the distribution system on the basis that a piece of paper is missing from the file, rather than on the basis of any inquiry into the nature, scope, conduct or completion of the project (Company Brief at 123-124).

ii. Specific Projects

The Company argues that it has provided detailed information for all specific projects as required under the standard for inclusion in rate base, which demonstrate that the capital additions were prudently made and are used and useful (Company Brief at 119, citing Exh. NG-JHP-1, at 9-11).[74] The Company contends that for specific projects costing more than $50,000, it provided: the project cover sheet; approved amount; actual cost; cost variance information; the appropriate number of units associated with the actual capital placed in service; and project sanction, re-sanction, and closure papers (Company Brief at 119, citing Exh. NG-JHP-1, at 9-11). Further, the Company claims that all 20 of the projects have variances of less than ten percent (Company Reply Brief at 17). In this regard, the Company notes that its policy is to evaluate and document project cost variances only if the aggregate costs of the suite of funding projects exceeds "tolerance," which for these projects was ten percent (Company Brief at 124; Company Reply Brief at 17). Further, the Company argues that it

[74] Of the $6.5 million for which the Attorney General recommends exclusion, the Company argues that approximately $3.2 million is attributable to O&M expenditures, and another $1.2 million represents costs incurred on funding projects that are not yet placed in service, and, therefore, are not part of the Company's rate base request (Company Brief at 122).

submitted to the Department documentation including variance analyses with the Company's rebuttal testimony on April 19, 2016 (Company Reply Brief at 17, citing Exh. NG-JHP-Rebuttal-2). Therefore, the Company asserts that the Department should reject the Attorney General's recommended disallowance (Company Brief at 124; Company Reply Brief at 17-18).

iii. Storm Capital Programs

The Company argues that it provided sufficient variance explanations regarding these programs to warrant recovery of the $11.7 million in costs recommended for disallowance by the Attorney General (Company Brief at 127, Company Reply Brief at 19). In this regard, the Company contends that for storm programs it uses a budgetary method used to set aside a dedicated amount of money each year for mandatory work necessary to restore power after significant storm damage (Company Brief at 127). The Company contends that because storms are unpredictable, it is prepared to overspend the budgeted amounts to complete restoration efforts as necessary (Company Brief at 127). Thus, the Company asserts that any failure to explain why it was unable to accurately predict restoration costs is not a legitimate basis for disallowance (Company Brief at 127). Moreover, the Company notes that the Attorney General first challenged the variance explanations on brief, after having had substantial opportunity to inquire about an explanation provided nearly four years ago in the Company's CapEx filing in D.P.U. 12-48, and again in the Company's initial filing in this proceeding (Company Brief at 128, citing Attorney General Brief at 20).

iv. Blanket and Program Projects

The Company disagrees with the Attorney General's assertion that the late filing of documentation relating to blanket and program projects is a valid basis for disallowing $37.8 million in blanket and program projects (Company Brief at 125). The Company argues that its closure papers adequately support inclusion of the program and blanket projects in rate base (Company Brief at 125). Specifically, the Company contends that it is not required to anticipate and provide with the initial filing the entire evidentiary record in support of each component of its rate filing because it is the function of the adjudicatory process to establish an evidentiary record upon which the Department can base a decision on the matters at issue (Company Brief at 125). Further, the Company notes that it did include in its initial filing both summary and project-specific documentation for every project over $100,000, and that this documentation provided more than sufficient information to facilitate the efficient conduct of the proceeding (Company Brief at 125, citing Exhs. NG-JHP-3; NG-JHP-4).

In addition, the Company argues that it submitted the majority of the closure papers sought by the Attorney General on May 3, 2016, after providing notice in rebuttal testimony of its intent to make the supplemental filing (Company Brief at 126, citing Exhs. NG-JHP-Rebuttal-1, at 19; NG-JHP-Rebuttal-2). The Company notes that the Attorney General did not object to the Company's production plan (Company Brief at 126).

5. Analysis and Findings

a. Motion to Strike

i. Introduction

The Hearing Officer adjourned hearings on May 26, 2016 (Tr. 15, at 1695). On June 2, 2016, National Grid filed a supplemental response to information request DPU-7-23 and a supplemental attachment to the rebuttal testimony of one of its witnesses (Exhs. DPU-7-23 (Supp.); NG-JHP-Rebuttal-2 (Supp.)). On June 10, 2016, the Attorney General filed a motion to strike these documents as extra-record information. On June 17, 2016, National Grid filed a response to the Attorney General's motion to strike.

Exhibit DPU-7-23 (Supp.) contains an additional worksheet showing that certain of the Company's capital projects are part of a larger group of projects. Exhibit NG-JHP-Rebuttal-2 (Supp.) contains reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015.

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the documents filed on June 2, 2016,[75] constitute extra-record evidence for which the Company is required to file a motion to reopen the record and make a showing of good cause pursuant to 220 C.M.R. § 1.11(8) (Attorney General Motion at 1, 2). Further, she contends that the Department has made clear that, except for updates to routine information already provided in the record (e.g., property tax bills) a motion to reopen the record must be filed and granted before the testimony or exhibits are "thrust upon the trier of

[75] The Attorney General contends that the information provided was voluminous, provided additional final cost information for certain blanket and program costs, and contained substantial changes to previously filed record evidence (Attorney General Motion at 1).

fact," noting that "one cannot unring a bell" (Attorney General Motion at 2, quoting Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989)). Thus, the Attorney General asserts that if the Department allows the subject documents into the record, it will deny the Attorney General's and other intervenors' due process rights to conduct discovery and cross-examination,[76] and will result in rates that are not just and reasonable (Attorney General Motion at 1-4, citing G.L. c. 30A § 11(3); 220 C.M.R. §§ 1.11; D.P.U. 10-70, at 195-96; MediaOne/New England Telephone, D.T.E. 99-42/43, p. 17-18 (1999); Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 9 (1998); New England Telephone and Telegraph Company, D.P.U. 94-50, at 62 (1995); Boston Edison Company, D.P.U. 90-335, at 7-8 (1992); Payphone Inc., D.P.U. 90-171, at 4-5 (1991)).

Further, the Attorney General argues that even if the Company had filed a motion to reopen the record, it could not have made a showing of good cause because much of the supplemental material concerned activity that occurred several years ago and should have been filed with the Company's initial filing (Attorney General Motion at 3, citing D.P.U. 14-150, at 50). Additionally, she notes that the Company failed to timely provide the subject documentation in response to information requests issued during the proceedings (Attorney General Motion at 3, citing Exhs. DPU-7-23; AG-21-2). The Attorney General further asserts that "good cause" is an important safeguard to intervenors' procedural due process rights and that no good cause can exist for the late-filing of these materials because the Company had

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76 The Attorney General also argues that because the Company filed the Supplemental Material so close to the briefing deadline, the Attorney General did not have adequate time for even a cursory review of the documents prior to filing briefs (Attorney General Motion at 1, citing D.P.U. 10-70, at 195-196).

ample time and multiple opportunities to supply the supplemental materials (Attorney General Motion at 3).

(B) Company

National Grid argues that the evidentiary record did not close on May 26, 2016, because the Department made provisions for the Company to provide the subject documentation after the conclusion of evidentiary hearings (Company Response at 3). Specifically, the Company argues that during the May 3, 2016, evidentiary hearing, the Hearing Officer recognized that the Company provided some of its closure papers with its rebuttal testimony, but that some had not been compiled (Company Response at 3, citing Tr. 3, at 435). The Company argues that the Hearing Officer then issued Record Request DPU-13 for the Company to update its blankets and programs plant additions with actual cost information once the remaining closure papers were completed (Company Response at 3, citing Tr. 3, at 438). Additionally, National Grid claims that the Hearing Officer accepted the Company's representation that the actual cost information for blanket and programs would not be known until June 1, 2016, and, therefore, extended the due date for the Company's response to Record Request DPU-13 from May 12 to June 1, 2016 (Company Response at 3, citing Tr. 3, at 435-336, 438). Thus, National Grid argues that the Hearing Officer explicitly left the evidentiary record open for the production of this documentation, and the Company provided the information in conjunction with the supplemental attachment to the rebuttal testimony and the response to Record Request DPU-13 (Company Response at 5). Accordingly, the Company argues that it was not required to file a motion to reopen the record (Company Response at 5).

Further, the Company argues that even if the Hearing Officer had not left the evidentiary record open to receive the subject documentation, the Attorney General fails to cite any Department decision, regulation or rule to support the notion that the evidentiary record is closed on the last day of evidentiary hearings, absent specific exceptions or requests to keep open the record (Company Response at 4). According to the Company, it is the Department's long-standing practice to keep the record open after the close of evidentiary hearings for admission of information relevant to its determinations, including specified updates to schedules and responses to record requests (Company Response at 4, citing Cambridge Electric Light Company, D.P.U. 92-250 (1993); The Berkshire Gas Company, D.P.U. 90-121 (1990)).

Moreover, the Company argues it has a continuing obligation to update the record if it obtains new information pertinent to the proceeding and is also under a continuing obligation to "seasonably amend its responses to discovery, direct examination, and cross-examination as soon as it obtains information that a response was incorrect or incomplete or that a response, though correct when made, is no longer true or complete" (Company Response at 5, quoting Bay State Gas Company, D.P.U. 12-25, at 106-107 (2012); citing 220 C.M.R. § 1.06(6)(c)(5); D.P.U. 09-30, at 174; D.T.E. 02-24/25, at 32-33; Riverside Steam and Electric Company, D.P.U. 88-123-B at 57-58 (1991); Aquarion Water Company of Massachusetts, D.P.U. 08-27-B at 22 (2010)). The Company contends that this obligation continues beyond evidentiary hearings and even after a base rate case proceeding has concluded (Company Response at 5, citing D.P.U. 12-25, at 106-107). In this regard, National Grid claims that capital project documentation, relevant to the Department's review of the Company's petition, should be accepted into evidence even if filed after the close of evidentiary hearings and unaccompanied by a motion to reopen the record (Company Response at 6, citing D.P.U. 10-55, at 190).

Finally, the Company argues that accepting the subject documentation into the record would not prejudice the Attorney General (Company Response at 6). The Company contends that most of its closure papers supporting the blanket and program capital projects were filed in its rebuttal testimony (Company Response at 6, citing Exhs. NG-JHP-Rebuttal-1, at 19-20). Further, National Grid asserts that the Attorney General had adequate notice of the Company's intention to file supplemental closure papers after the conclusion of evidentiary hearings and should have raised any concerns at the May 3, 2016 evidentiary hearing when reasonable accommodations could have been made to the briefing schedule (Company Response at 7).

iii. Analysis and Findings

First, the Department will not strike Exhibit DPU-7-23 (Supp.) because we find that it simply was an alternative presentation of an earlier version of the response, modified to show which specific projects were part of larger groups (compare Exh. DPU-7-23, Att. (Rev.) with Exh. DPU-7-23, Att. (Supp.)). In addition, in the supplemental response to information request DPU 7-23, the Company replicated its response to Record Request DPU-12 and separated the total investment for specific projects into two amounts – one for standalone specific projects and one for specific projects that were part of a group (compare Exh. DPU-7-23, Att. (Supp.) with RR-DPU-12). The total number of projects, the cost information for the projects, and the associated revenue requirement did not change with the filing of the supplemental response to information request DPU 7-23 (Exhs. DPU-7-23, Att. (Rev.); DPU-7-23, Att. (Supp.); NG-RRP-2; NG-RRP-2 (Rev. 3); RR-DPU-12).

However, unlike the materials contained in Exhibit DPU-7-23 (Supp.), the documentation filed with Exhibit NG-JHP-Rebuttal-2 (Supp.) does contain an additional eighty pages of reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015, that were not previously provided earlier in the docket (Exh. NG-JHP-Rebuttal-2 (Supp.)). Given that these documents were filed a full week after evidentiary hearings ended, and that there was no valid explanation offered as to why these documents were not produced prior to that time given multiple requests for the type of information included herein, neither the Department nor the intervening parties had the opportunity to inquire about them through discovery or cross examination.

Further, despite the Company's argument to the contrary, we find that the record was not left open, either expressly or implicitly, for the production of these documents. At the close of evidentiary hearings, the record was left open for the production of specific information that did not include the subject documentation (Tr. 15, at 1691-1693). Additionally, the Hearing Officer's inquiry earlier in the hearings regarding the status of documents did not constitute a ruling on the propriety of allowing the information into the evidentiary record (Tr. 3, at 435). Further, we find that the Hearing Officer's issuance of Record Request DPU-13 was in no way related to the production of the subject documents. This Record Request asked the Company to update information, which previously was provided in the response to Exhibit AG-7-5, regarding annual capital expenditures since 2009 (Tr. 3, at 436-438). The Hearing Officer did not include in this record request any specific project documentation for any capital additions, let alone the subject documents that ultimately were filed on June 2, 2016 (Tr. 3, at 436-438).

Additionally, we note that the documents filed with Exhibit NG-JHP-Rebuttal-2 (Supp.) should have been produced with the initial filing in this case, particularly those documents that pertain to investments that were placed in service in 2013 and 2014. At a minimum, these materials should have been made available in response to the discovery process that occurred prior to evidentiary hearings, or during the filing of rebuttal testimony, once it became known that these materials were still omitted from the case. Pursuant to the Company's own capital authorization policies, these documents should have been completed at the close of the fiscal years for 2013 and 2014, and available well in advance of their filed date (RR-DPU-43, Atts. 2-3). Further, these documents should have been provided as part of the Company's annual CapEx filings in July 2014 and July 2015.

Based on these considerations, we conclude that the reauthorization documents and closure papers for certain program projects placed in service in FY 2013, 2014, and 2015, produced on June 2, 2016, in Exhibit NG-JHP-Rebuttal-2 (Supp.), were not timely filed. Further, we find that the Attorney General was precluded from conducting a meaningful review of these documents and from inquiring about the specific program projects either through discovery or cross examination. Consequently, the Department allows the Attorney General's motion to strike and will not consider these documents in the determination of whether these projects qualify for inclusion in the Company's rate base.

b. Plant Additions

i. Standard of Review

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

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

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Boston Gas Company/Colonial Gas Company/Essex Gas

Company, D.P.U. 10-55-B at 13-16 (2013); D.P.U. 09-30, at 144-145; Boston Gas Company, D.P.U. 96-50 (Phase I) at 21-24 (1996); Massachusetts Electric Company, D.P.U. 95-40, at 7-8 (1995); D.P.U. 93-60, at 25-26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993). In addition, the Department has stated that:

> In reviewing the investments in main extensions 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.

ii. Introduction

The Company reported a total of $1,189,550,457 in rate base additions and $93,788,658 in cost of removal for a combined capital investment total of $1,283,329,114 from January 1, 2009 through June 30, 2015 (Exhs. NG-JHP-1, at 5; DPU-7-23, Att. (Supp.)). National Grid reported 1,257 specific projects for $509,652,488; 62 blanket projects for $463,986,528; and 99 program projects for $217,111,440 (Exh. DPU-7-23 Att. (Supp.); RR-DPU-12). The Company then reduced its total plant additions by $1,200,000 to correct an error found in the D.P.U. 11-18 audit to arrive at the total investment of $1,189,550,457 (Exhs. NG-JHP-1, at 12; DPU-7-23, Att. (Supp.); RR-DPU-12)). We find that this correction is appropriate.

iii. Capital Authorization Policies

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 (Exh. NG-JHP-4, at 1). A specific project is approved for the total cost of a defined body of work and will be closed once the work is complete (Exh. NG-JHP-4, at 1; RR-DPU-43, Att. 2, at 9).

In other words, specific projects are set up to perform a specifically identified scope of work that can span multiple years and can contain one or many work orders at any given time (Exh. NG-JHP-4, at 1, 8, 12). A blanket project is set up to collect high volume, smaller dollar work orders within a certain budget classification (Exh. NG-JHP-4, at 8; RR-DPU-43, Att. 2, at 8). A program project contains work orders for similar types of construction following a specific strategy (e.g., recloser installations) (Exh. NG-JHP-4, at 12; RR-DPU-43, Att. 2, at 9). Blanket and program projects are budgeted and approved annually (Exh. NG-JHP-4, at 12). Other annually-approved projects, such as storm-related projects, are categorized as "program" projects in order to indicate that they are not blanket projects (Exh. NG-JHP-4, at 12).

The Company maintains a written DOA policy,[77] and written sanctioning procedures,[78] for specific, blanket, and program projects (RR-DPU-43 and Atts. 1-3). A DOA is an authorization to enter into contracts, other external commitments, or to take (or not) other actions that might result in an obligation by National Grid (RR-DPU-43, Att. 2, at 8). A DOA is obtained at the funding project level (RR-DPU-43, Att. 2, at 8). Re-sanctioning is the process of receiving authorization to revise the existing approved cost, scope, or schedule (RR-DPU-43, Att. 2, at 8). The Company's capital authorization policies and procedures differ for projects

[77] The Company has not made any material changes to its DOA policy since 2009 (RR-DPU-43).

[78] Prior to May 2011, the Company's capital authorization process consisted of department-specific sanction committees, with separate processes and sanctioning templates (RR-DPU-43). On May 31, 2011, the Company began using the USSC for all utility services using a common template and single sanction procedure (RR-DPU-43). The USSC originally reviewed and approved all projects with estimated spending at or above $1 million (RR-DPU-43). In 2013, the Company's capital authorization policy was revised to focus the USSC's review and approval on projects greater than $8 million and to create a subcommittee responsible for reviewing and approving projects greater than $1 million, but at or less than $8 million (RR-DPU-43).

with expected costs of less than $1 million and for projects with expected costs at or above $1 million (RR-DPU-43 and Atts. 1-3).

(A) Projects Under $1 Million

The requested DOA specific projects with costs under $1 million constitute the gross expected expenditure (i.e., the Company does not subtract from the DOA amounts for anticipated contributions in aid of construction ("CIAC") or other contributions) (RR-DPU-43, Att. 2, at 4). The DOA for a specific funding project is revised prior to exceeding the approved DOA (RR-DPU-43, Att. 2, at 4).[79] Specific funding projects must be re-sanctioned as soon as the actual cost is, or is forecasted to be, ten percent above the authorized expenditure or $25,000, whichever is greater (RR-DPU-43, Att. 2, at 6).[80]

The responsible person must provide written justification for the re-sanctioning along with the new requested DOA amount for the funding project using a "Change in DOA Request Form" (RR-DPU-43, Att. 2, at 7). The higher the total cost of the funding project, the greater the level of detail is required in the documentation to properly justify the funding project re-sanction (RR-DPU-43, Att. 2, at 7). The justification must be clear, concise and accurate and should contain enough information to allow a full understanding of the reasons for the increase (RR-DPU-43, Att. 2, at 7). Once approval is obtained, the funding project DOA in the

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79 In the event a funding project is originally estimated to be under $1 million but the forecasted or actual costs exceed $1 million, the funding project must be re-sanctioned pursuant to the policies applicable to projects with costs over $1 million, as described below (RR-DPU-43, Att. 2, at 6).

80 For all three types of projects the responsible individual must obtain re-sanction of all funding projects that exceed their authorized spending limit on a timely basis, but in no case later than 60 days after being notified that the project has exceeded the authorized spending limit (RR-DPU-43, Att. 2, at 6).

Company's computer system will be updated (RR-DPU-43, Att. 2, at 7). Specific projects may be grouped with other related specific projects and the Company considers these groups of projects at the aggregate level when determining whether the project is over budget (Tr. 3, at 426).

Blanket and program funding projects under $1 million are sanctioned at the start of each fiscal year to reflect the upcoming budget and routed for DOA approval (RR-DPU-43, Att. 2, at 5). Blanket work orders are linked to blanket funding projects and must not exceed $100,000 (RR-DPU-43, Att. 2, at 5). The DOA requested for blanket and program funding projects constitutes the gross expected expenditure (i.e., the Company does not subtract amounts for anticipated CIAC or other contributions) (RR-DPU-43, Att. 2, at 5). Blanket and program projects under $1 million are monitored on a monthly basis and revised with explanations within 60 days of the end of the fiscal year (RR-DPU-43, Att. 2, at 6). Blanket projects require a USSC closure paper[81] (RR-DPU-43, Att. 2, at 6).[82] Programs of less than $1 million require change in DOA forms, but do not require closure papers (Exh. NG-JHP-4, at 13; Tr. 3, at 431-432). Additionally, program projects under $100,000 do not require change in DOA forms or closure papers (Tr. 3, at 430-432).

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81 A closure paper is prepared at the completion of a funding project that details the financial and objective outcomes of the funding project (RR-DPU-43, Att. 3, at 13).

82 We note that there appears to be an inconsistency in the Company's re-sanctioning procedures and other documentation with respect to whether closure papers are completed for program projects under $1 million (Compare RR-DPU-43, Att. 2, at 6 with Exh. NG-JHP-4, at 13). Based on other documentation in the record and the Company's testimony, it appears that the Company's policy is to not require a closure paper for program projects under $1 million (see, e.g., Exhs. NG-JHP-3(f), JHP-2, at 13; NG-JHP-4, at 13; Tr. 3, at 431-432). As noted below, the Department directs the Company to clarify the capital authorization policies on this point.

Additionally, capital funding project overrun reports are produced on a monthly basis (RR-DPU-43, Att. 2, at 7). These reports identify funding projects that have exceeded or are forecasted to exceed the authorized DOA basis (RR-DPU-43, Att. 2, at 7). Within ten business days, the responsible personnel must prepare a written plan to bring the affected funding project within DOA limits (RR-DPU-43, Att. 2, at 7).

For the Company's annual capital investment report filing, the Company prepares variance analysis reports for blanket and program funding projects on a fiscal-year basis (see, e.g., Exh. NG-JHP-4, at 18; Tr. 3, at 431-431). For purposes of providing variance explanations, the Company groups related blanket projects together and related program projects together (Tr. 3, at 431-431).

(B) Project Costs at or above $1 Million

For all types of projects at or above $1 million a sanction paper is used to approve the expenditure (RR-DPU-43, Att. 3, at 5). A sanction paper is the document submitted to the USSC for project approval and is considered the final approval to undertake the funding project (RR-DPU-43, Att. 3, at 16). A sanction, as opposed to a partial sanction, is generally prepared for the full scope and cost of the funding project (RR-DPU-43, Att. 3, at 16). Generally the costs are expected to have a variance tolerance of plus or minus ten percent (RR-DPU-43, Att. 3, at 16). The funding project amount to be sanctioned, and for which a DOA is requested, shall be the gross expected expenditure (i.e., the Company does not subtract amounts for anticipated CIAC or other contributions) (RR-DPU-43, Att. 3, at 5). Closure papers are required for all funding projects of $1 million or greater (RR-DPU-43, Att. 3, at 9).

A specific funding project of over $1 million must be re-sanctioned within 60 days of notification that the cost is forecasted to vary outside of the tolerance approved in the project sanction paper (RR-DPU-43, Att. 3, at 8). Re-sanction papers should not re-state the original need, but must include a detailed explanation of the new sanction requirements and why they have changed from those that were originally approved (RR-DPU-43, Att. 3, at 9). In addition, the re-sanction paper should include details of lessons learned including an explanation of any significant variances in cost (RR-DPU-43, Att. 3, at 9). If the lessons learned and explanations are not fully known at the time, they must be included in the closure paper (RR-DPU-43, Att. 3, at 9). Specific funding project closure papers shall be completed as soon as possible after all work orders and projects are closed (RR-DPU-43, Att. 3, at 9). Related specific funding projects shall be included in one investment document (RR-DPU-43, Att. 3, at 10). A funding project is related to another funding project if it cannot fully accomplish its intended purpose unless the other funding project is also carried out (RR-DPU-43, Att. 3, at 10). These related funding projects should be identified in a sanction paper (RR-DPU-43, Att. 3, at 11). The Company considers these groups of projects at the aggregate level when determining whether the project is over budget (Tr. 3, at 426).

Blanket and program funding projects at or above $1 million are approved for each fiscal year (RR-DPU-43, Att. 3, at 8). Blanket and program funding projects may not be segmented into smaller pieces in order to sanction the spending at a lower level of authority than would otherwise be required (RR-DPU-43, Att. 3, at 8). For blanket projects, a closure document is presented at the end of each fiscal year (Exh. NG-JHP-4, at 18, 2; RR-DPU-43, Att. 3, at 8). For program projects, a closure document is presented at the end of each fiscal year unless otherwise specified in the strategy or sanction paper (Exh. NG-JHP-4, at 18, 2; RR-DPU-43, Att. 3, at 8). Program funding project closure papers shall be completed as soon as possible after all work orders and projects are closed (RR-DPU-43, Att. 3, at 9).

For the Company's annual CapEx filing, the Company prepares variance analysis reports for blanket and program funding projects on a fiscal-year basis (see, e.g., Exh. NG-JHP-4, at 18; Tr. 3 at 431-431). For purposes of providing variance explanations, the Company groups related blanket projects together and related program projects together (Tr. 3, at 431-431).

iv. Project Documentation

The Company provided project documentation at various points in this proceeding. As part of its initial filing, the Company provided the filings made in each of the previous CapEx filings, as well as documentation relating to capital investments made during the first six months of 2015 (Exhs. NG-JHP-3; NG-JHP-4). As noted above in Section VII.B.3, the Company provided, with its initial filing, various forms of documentation for specific projects over $50,000 and all blanket and program projects including: (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; (3) sanction papers; (4) a retirement report; (5) a direct/indirect summary report; (6) a work order asset addition report; (7) a project cost summary (see, e.g., Exhs. NG-JHP-3; NG-JHP-4). The Company also provided closure papers for some specific projects (see, e.g., Exhs. NG-JHP-3; NG-JHP-4). For blanket and program projects, the Company also provided a fiscal year variance analysis report and a fiscal year closure paper (Exh. NG-JHP-4, at 12, 13).[83]

Over the course of the proceeding, the Company provided additional documentation including a variance explanation for a specific project, closure papers for 26 specific projects, closure papers for five specific projects and eight program projects (Exhs. DPU-17-23; AG-21-1, Atts. 1, 2; NG-JHP-Rebuttal-2, at 18-20). Additionally, on May 3, 2016, the Company provided closure papers for 22 blanket projects (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)). Further, as noted above in Section VII.B.5.a.i, on June 2, 2016, the Company provided reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015, which the Department has excluded from the evidentiary record as provided in Section VII.5.a.iii above (Exh. NG-JHP-Rebuttal-2 (Supp.)). On that date, the Company also provided a supplemental response to information request DPU-7-23, showing the Company's specific projects that are combined into a larger group of projects (Exh. DPU-7-23, Att. (Supp.)). As discussed below, the Attorney General challenges the sufficiency of the documentation provided for 20 specific projects, 32 blanket projects, 47 program projects, and two storm program projects (Attorney General Brief at 12-19).

The Department finds that a project cost document production threshold of $50,000 for specific projects is appropriate for a company the size of National Grid. See D.P.U. 14-150,

83 The Company initially did not provide closure papers for 31 specific projects, but provided them through discovery. Nor did it initially provide blanket project closure papers for fiscal years 2013 and 2014, which were provided at the beginning of hearings. Also, the Company initially did not provide closure papers for seven program projects over $1 million and reauthorization forms for 14 program projects over $100,000, but they were provided after the close of hearings and have been excluded from the record above.

at 58; New England Gas Company, D.P.U. 11-42, at 3 n.4 (2013); D.P.U. 10-114, at 81, n.67. Nevertheless, document production thresholds used by the Department in the discovery process do not mean that projects of a lower value are exempt from scrutiny or the requirement that a company maintain adequate documentation to support the prudence of these capital additions. D.P.U. 14-150, at 58. Rather, the Department and intervenors may inquire into any project regardless of its final cost. D.P.U. 14-150, at 58; D.P.U. 12-25, at 77; D.P.U. 10-55, at 188.

v. Specific Projects

The Company seeks inclusion of $509,652,488 in investments for 1,253 specific projects, including the cost of removal (Exh. DPU-7-23, Att. (Supp.); RR-DPU-12). There were 772 specific projects with in-service additions greater than $50,000 between January 1, 2009 and June 30, 2015 (Exh. DPU-10-12 (Att.)). Of those specific projects, 360 had variances in excess of ten percent (Exh. DPU-10-12 (Att.)). The Attorney General recommends that the Department exclude 20 of these projects from rate base because the Company did not provide a variance explanation (Attorney General Brief at 11-12).

We first consider the 752 uncontested specific projects. The Department has reviewed the information supporting the Company's completed projects, including all supporting documents described above (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 and Atts. 1-3; DPU-17-23; AG-21-1, Atts. 1, 2). Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of the Company's uncontested specific projects in rate base. We now turn to the 20 contested specific projects.

A company is required to provide a reasonable explanation for cost variances, based on the specifics of each project, sufficient for the Department to evaluate the reasonableness and prudence of any cost variance. D.P.U. 14-150, at 50; D.P.U. 13-75, at 95, 105; D.P.U. 12-25, at 79-80, 82; D.P.U. 10-114, at 85-87; D.P.U. 10-55, at 179-180. If a company adequately justifies the reasons for any cost variance, the Department will consider the costs of the project eligible for inclusion in rate base. D.P.U. 14-150, at 50. If, however, a company is unable to justify the reasons for a cost variance, the Department will exclude the excess costs to the extent that the Company has not met its burden of proof. D.P.U. 14-150, at 50-51; D.P.U. 13-75, at 114; D.T.E. 03-40, at 68; D.P.U. 95-118, at 49-55. The Department has directed companies to address the cost variances for capital expenditures between the amount approved for projects and the actual amount required to complete the projects. D.P.U. 10-79, at 7. The Department has approved a company's use of authorized amounts that are refined over time for purposes of conducting a variance analysis because they are more reflective of the costs to be incurred by the Company in undertaking the approved project. D.P.U. 15-80/D.P.U. 15-81, at 75.

The Department requested an explanation for the variance on 23 specific projects (Exhs. DPU-17-1 through DPU-17-23). For 20 of these projects, the Company responded that the projects were part of a larger group of related projects that in the aggregate did not exceed the ten percent tolerance and, therefore, the Company did not perform a variance investigation (see, e.g., Exh. DPU-17-3). Based on the Company's internal policies, it groups related projects and considers these groups at the aggregate level when applying the threshold required for a variance explanation (see, e.g., Exh. DPU-17-3; Tr. 3, at 426-427). The Department finds that the Company's grouping practice is a sufficient project management tool for reviewing cost control for the ratemaking treatment of plant additions. Therefore, the Department will not require variance analyses for specific projects within the groupings. In future filings involving plant additions, i.e., base rate case, CIRM filing, the Department will continue to review the Company's project management tools to ensure that there adequate cost control measures.

In any event, the Company stated that reauthorization documents adequately explain the reasons for a reauthorization at the specific project level (Tr. 3, at 425-429). With the documentation provided in the instant case, the Department will review the capital project documentation and closing reports for all specific projects that are part of a group of related projects to determine whether the expenditures are prudently incurred.

The Department has reviewed the documentation the Company provided for these 20 specific projects,[84] including all supporting documents (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; JHP-Rebuttal-2; DPU-17-23; AG-21-1, Atts. 1,2). For the 20 specific projects, the Company provided various forms of documentation including, but not limited to, project summary sheets, project approval reports, authorization documents, retirement reports, asset addition reports, project cost summary reports, and closure papers.[85] The closure papers or re-sanction papers contain reasons for the reauthorization requests during the lifecycle of the project.[86] To the

[84] The 20 specific projects are: C008666; C005339; C014549; C023591; C036385; C028886; C002364; C002388; C012018; C012502; C024120; C005342; CD01253; C001423; C028871; C029104; C031552; CD01174; C031324; and C002504.

[85] The Company did not provide a closure paper for Project C008666, stating that the current sanction process did not exist at the time the project was progressing (Company Reply Brief at 17).

[86] Exhs. NG-JHP-Rebuttal-2 at 13, 28, 39 44, 50, 57; NG-JHP-3(b), JLG-6 at SPCFC-1275; NG-JHP-3(c), JLG-6 at SPFC-1231, 1369; NG-JHP-3(d), JLG-6, at SPFC-6, 1112-1116; NG-JHP-3(f), JHP-6, at SPFC 1270-71, 2328; NG-JHP-4, at SPFC-357.

extent that these projects had a variance between the final approved amount and the actual spent amount,[87] that variance was less than ten percent and, therefore, would not trigger a separate variance explanation under the Company's policies (see, e.g., Exh. DPU-17-3; Tr. 3, at 392, 398, 426-427).

The explanations provided for the variances and reauthorizations during the lifecycle of the projects include unforeseen environmental issues, increases in project scope, revisions to design, increase in materials and labor costs, low estimates, project initially only given a partial sanction for preliminary engineering, and various other project-specific issues.[88] While most of these explanations were provided at the group level, not the individual project level, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of these 20 projects in rate base.

vi. Storm Capital Programs

The Company reported storm capital programs using five project numbers: C014821, C014822 C21594, C02216, and C22217. The Attorney General specifically challenges the sufficiency of the variance explanations for two storm program projects for fiscal year 2010,

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87 We have approved a company's use of authorized amounts that are refined over time for purposes of conducting a variance analysis because they are more reflective of the costs to be incurred by the Company in undertaking the approved project. D.P.U. 15-80/D.P.U. 15-81, at 75.

88 See, e.g., Exhs. NG-JHP-Rebuttal-2 at 13, 28, 39 44, 50, 57; NG-JHP-3(a), JLG-6, at SPFC-1624; NG-JHP-3(c), JLG-6, at SPFC-1231, 1369; NG-JHP-3(d), JLG-6, at SPFC-6, 1112-1116; NG-JHP-3(e), JLG-6, at SPFC-3446; NG-JHP-3(f), JHP-6, at SPFC-1270-71; NG-JHP-4, at SPFC-357, 525.

projects C014821 and C014822, totaling a $ 2.4 million variance; and one fiscal year 2012 project, C014821, with a $9.3 million variance (Attorney General Brief at 20). Additionally, the Attorney General, as part of her challenge of program projects discussed below, contests the sufficiency of the documentation for storm programs C014821, C21594, C02216, and C22217, which span FYs 2013 through 2015.[89]

The Company provided closure papers and variance analysis reports with its initial filing for the two fiscal year 2010 projects and provided a closure paper containing a variance explanation for the fiscal year 2012 project (Exhs. NG-JHP-3(b), JLG-8, at PRGM-0329, 341; NG-JHP-3(d), JLG-8, at PRGM-163; DPU-19-1; DPU-19-2). The variance explanation for the fiscal year 2010 projects states that storm restoration programs are approved annually based on historic trends and that the cost of mandatory storm restoration activities are strictly dependent on size/scale of storms incurred during the year (Exh. NG-JHP-3(b), JLG-8, at PRGM-0329, 341). The variance explanation provided by the Company for the fiscal year 2012 project states that three major storms resulted in significant damage across the state's infrastructure (Exhs NG-JHP-3(d), JLG-8, at PRGM-163; DPU-19-40).[90] The Company also explained that in reporting the costs to the Department, the Company mistakenly used the budgeted amounts for the fiscal year and not the final authorized amount from the closure papers, and that if the correct amount had been used, the variance would be minimal (Exhs. DPU-19-1; DPU-19-2; DPU-19-40; see also Exh. DPU-7-23, Att. (Rev.)).

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89 We address the fiscal year 2013-2015 storm programs in the section below.

90 The storms were a tornado in June 2011; Tropical Storm Irene in August 2011; and a major snowstorm in October 2011 (Exh. DPU-32-4).

We find that the variance explanations provided are sufficient for purposes of storm program projects. The Company establishes budgets for storm program projects based on multi-year historic trends (Exh. NG-JHP-1, at 19). The work performed to restore service is inherently unplanned and not fully quantifiable until after the work has been performed (Exh. NG-JHP-1, at 19). Therefore, we will not exclude these projects from rate base on this basis.

Further, we note that the Department imposed substantial fines on National Grid after determining that restoration efforts related to two storms were inadequate, in part, because the Company mobilized insufficient resources. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. However, in this instance, we find that the Department's imposition of those fines does not automatically warrant a disallowance of the costs that the Company incurred in responding to these storms. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. The Department did not make a finding that any of the costs the Company incurred in responding to the storm were imprudent under the standard of review for plant additions. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. Instead, we stated that if the Company seeks recovery of storm costs in a future Department proceeding, the Department will determine whether the Company's storm expenses were prudently incurred in that proceeding and whether or not to deny any of the Company's storm related expenses. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41, citing Fitchburg Gas and Electric Light Company, D.P.U. 09-01-A at 195 (2009); D.P.U. 93-60, at 24. Based on our findings above, we conclude that the costs for these storm capital programs projects were prudently incurred and that the capital investments are used and useful.

vii. Blanket & Program Projects

The Company seeks inclusion of $217,111,440 in investment for 99 program projects and $463,986,528 for 62 blanket projects (Exh. DPU-7-23, Att. (Supp.); RR-DPU-12).[91] As noted above, for blanket projects, the Company provided project documentation consisting of: (1) fiscal year blanket project summary sheets; (2) project cost summaries; (3) fiscal year approval documents; (4) fiscal year summary project variance analyses[92] and closure papers;[93] (5) calendar year work order asset detail reports; (6) calendar year retirement reports; and (7) direct/indirect summary reports (see, e.g., Exhs. NG-JHP-3; NG-JHP-4, at 10-13). In its initial filing, the Company did not provide closure papers for 31 blanket projects for FYs 2013 and 2014;[94] the Company filed them on May 3, 2016 (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)).

For program projects, the Company provided project documentation consisting of: (1) fiscal year program project summary sheets; (2) project cost summaries; (3) fiscal year

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91 The Company's programs and blanket projects are often reauthorized for the next fiscal year using the same project number. There are 99 unique program project numbers and 62 unique blanket project numbers, many of which repeat from year to year (Exh. DPU-7-23, Att. (Rev.)).

92 See, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803.

93 See, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-126-149; NG-JHP-3(c), JLG-7, at LNK-123-129; NG-JHP-3(f), JHP-7, at BLNK-101-110; NG-JHP-4, at 92).

94 These projects include: CBN0002; CBN0004; CBN0010; CBN0011; CBN0012; CBN0014; CBN0015; CBN0016; CBN0017; CBN0022; CBS0010; CBS0011; CBS0014; CBS0020; CBS0022; CBW0002; CBW0006; CBW0010; CBW0011; CBW0014; CBW0016; CBW0020; CN00420; CNM0002; CNM0004; CNM0010; CNM0011; CNM0014; CNM0017; CNM0020; and CNM0022.

approval documents; (4) fiscal year summary project variance analyses[95] and closure papers;[96] (5) calendar year work order asset detail reports; (6) calendar year retirement reports; and (7) direct/indirect summary reports (Exhs. NG-JHP-3; NG-JHP-4, at 10-13). The Company initially did not file closure papers for seven program projects of over $1 million;[97] it filed six of them on June 2, 2016 (Exh. NG-JHP-Rebuttal-2 (Supp.)). The Company did not initially file reauthorization paperwork for 14 program projects over $100,000 and less than $1 million, but filed them on June 2, 2016 (Exh. NG-JHP-Rebuttal-2 (Supp.)).[98]

As noted above, the Attorney General argues that the Company's submission of closure papers on May 3, 2016, for 31 blanket projects was untimely and recommends disallowance of $19.6 million dollars associated with these projects. The Attorney General challenges 47 program projects arguing that closure papers,[99] if any, were filed on June 2, 2016, and

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95 Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157.

96 Exhs. NG-JHP-3(b), JLG-8, at PRGM-331-343; NG-JHP-3(c), JLG-8, at PGRM-262-269; NG-JHP-3(d), JLG-8, at PGRM-156-168). Under the Company's capital authorization policies, program projects of less than $1 million do not require closure papers (Exh. NG-JHP-4, at 13).

97 On June 2, 2016, the Company filed closure papers for the following projects: C005490; C005500; C014821; C021594; C022216; and C022217. The Company did not file a closure paper for C006138.

98 On June 2, 2016, the Company filed Change in DOA forms for the following projects: C005543; C005469; C028147; C025810; C032270; CD00017; C025619; C025813; C027898; C031398; C031774; C035584; C049352; and CD01258.

99 The Attorney General argues that 47 program projects should be disallowed because, if closure papers were filed at all, they were filed after the close of the evidentiary hearings (Attorney General Brief at 16). We note that for 21 of the Attorney General's challenged projects, the Company filed closure papers (or other documentation) on June 2, 2016.

recommends disallowance of $18.2 million associated with these projects. The Attorney General, therefore, recommends disallowance of $ 37.8 million in blanket and program costs based on the lack of timeliness of filing the Company's closure papers.

(A) Blanket Projects

The Attorney General contests 31 of the Company's 62 blanket projects. We first consider the 31 uncontested blanket projects.[100] The Department has reviewed the information supporting the Company's 31 uncontested blanket projects including all supporting documents described above, with specific attention to the variance analyses (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to, increased residential applications for new business, increased applications for new attachments, increased levels of work relating to damage failures, increased equipment purchases, and various other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803). While these explanations were provided for a group of similar blanket projects, not the individual blanket projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

For the remaining 26 projects, the Company did not file any closure papers or documentation on June 2, 2016 (Company Brief at Appendix 1, Table 2).

100 The uncontested blanket projects are: CBN0009; CBN0013; CBS0002; CBS0004; CBS0006; CBS0009; CBS0012; CBS0013; CBS0015; CBS0016; CBS0017; CBS0025; CBW0004; CBW0009; CBW0012; CBW0013; CBW0015; CBW0017; CBW0022; CBW0070; CN00404; CN00504; CN00520; CNM0006; CNM0009; CNM0012; CNM0013; CNM0015; CNM0016; CNM0070; and CBW0025.

We now turn to the 31 contested blanket projects. The Company did not provide the FYs 2013 and 2014 blanket closing reports with its initial filing or during the discovery period. The Company did, however, provide closure papers for all of these projects on May 3, 2016 as a supplement to information requests propounded by the Department (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)). We share the Attorney General's concern that the Company was unable to provide these closure papers with its initial filing. Pursuant to the Company's capital authorization policies, these closure papers should have been completed at the close of FYs 2013 and 2014 and available at the time the Company filed its petition in this case (see RR-DPU-43 & Atts. 1-3). We find, however, that the filing of these closure papers was not so late as to prevent the Department and the parties enough time to conduct an adequate review of their contents. In a base rate proceeding, it is not unusual for a petitioner to provide documents and information during the course of hearings that it has not previously provided in the initial filing. Indeed, parties are under a continuing obligation to supplement discovery responses throughout the course of a proceeding. D.P.U. 12-25, at 106-107, citing 220 C.M.R. § 1.06(6)(c)(5); D.P.U. 09-30, at 174; D.P.U. 08-27-B at 22; D.T.E. 02-24/25, at 32-33; D.P.U. 88-123-B at 57-58.

The Department is not persuaded that the Attorney General was prejudiced by the production of these documents on May 3, 2016, which was the second day of hearings and before the record closed. Further, although the documents were produced the day before the Company's witness was to testify, the witness appeared on two consecutive days. Additionally, the Department reserved several days at the end of the evidentiary hearings for additional cross examination, so the Attorney General could have recalled the witness at that time. Moreover, the

Company's production constituted two ten-page documents, one for each fiscal year. The documents were not so voluminous as to prevent the Attorney General from reviewing them during the course of the evidentiary hearings to at least determine if she needed the Company's witness to appear again. Instead, the Attorney General concluded her questioning of the witness on May 5, 2016, two days after the documents were filed, and never asked that the witness be made available for further questioning on this or any other subject (Tr. 3, at 457).

More importantly, the closure papers provided by the Company on May 3, 2016, were largely duplicative of the project documentation already provided as part of the Company's initial filing (Exhs. NG-JHP-3(d), NG-JHP-3(e), JLG-7; NG-JHP-3(f), JHP-7). Specifically, the cost information contained in the closure papers is the same as the cost information in the project summaries and project cost summaries (Exhs. NG-JHP-3(d), NG-JHP-3(e), JLG-7; NG-JHP-3(f), JHP-7). Similarly, the variance analyses contained in the closure papers are the same as the variance analyses in the 2013 and 2014 blanket variance analysis reports (Exhs. NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803).

Based on these considerations, we find that a reasonable examination of the documents produced on May 3, 2016, was feasible given the number, length and nature of the documents, and the timing of their production vis-à-vis the evidentiary hearing schedule. Therefore, the Department will not exclude these projects from rate base due to the timing of the project documentation. We do, however, expect that National Grid will abide by its own capital authorization policies (i.e., preparing closure papers at the close of the fiscal year) as a reasonable means of maintaining adequate cost controls. Specifically, we note that the closure paper is the opportunity for the Company to reflect upon and document the lessons learned and to ensure that the Company has performed all close out activities (Exhs. DPU-20-31, at 3 (Supp.); DPU-20-35, at 3 (Supp.)). Given that the Company ultimately did provide sufficient cost information and variance analyses for the projects at issue, we find that the Company's failure to timely compile the closure papers (including documentation of lessons learned) is insufficient to support a finding that the Company failed to maintain adequate cost controls.

The Department has reviewed the information supporting the 31 contested blanket projects including all supporting documents described above, with specific attention to the variance analyses (see, e.g., Exhs. NG-JHP-3; DPU-20-1 through DPU-20-53; DPU-20-31 (Supp.); DPU-20-35 (Supp.); RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to, increased residential applications for new business, increased applications for new attachments, increased levels of work relating to damage failures, increased equipment purchases, and various other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at 3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803). While these explanations were provided for a group of similar blanket projects and not the individual blanket projects, we nevertheless find them sufficient under the Company's current policies to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of the Company's blanket projects in rate base.

(B) Programs

As noted above, the Attorney General challenges 47 total program projects arguing that closure papers, if filed at all, were filed after the close of evidentiary hearings. We first consider the 51 uncontested program projects.[101] The Department has reviewed the information supporting the Company's 51 uncontested program projects including all supporting documents described above, with specific attention to the variance explanations[102] and closing reports[103] (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to: increase in cost of transformers, carryover work from prior years due to weather or outages, incompatibility of parts purchased from different vendors, change in scope or strategy after initial budget was set, and other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-8, at PRGM-0323-0330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157). While these explanations were provided for a group of similar program projects, not the individual program projects, we

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101 The uncontested program projects are: C004494; C005495; C005499; C007266; C005543; C005442; C005446; C005447; C005451; C005453; C030604; C026264; C026279; C026280; C005509; C005514; C005519; C024499; C005558; C005826; C006629; C014322; C014323; C014324; C025239; C025899; C027002; C008407; C008414; C008511; C016123; C017453; C023512; C036906; C001379; C025320; C025683; C026056; C031397; C031778; C031831; C023491; C032027; C032570; C026761; C026836; C039984; C017892; C029780; C037962; and CAP0004.

102 The Company provided variance explanations for fiscal years 2010 through 2015 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157).

103 The Company provided closing reports with its initial filing for fiscal years 2010, 2011, and 2012 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-331-343; NG-JHP-3(c), JLG-8, at PGRM-262-269; NG-JHP-3(d), JLG-8, at PGRM-156-168).

find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

With respect to the 47 contested projects, the Attorney General argues that closure papers, if filed at all, were filed late on June 2, 2016, after the close of evidentiary hearings. First, we find that for 26 of the program projects the Company did not provide any documentation on June 2, 2016,[104] but did provide documentation with the initial filing as described above. The Department has reviewed the information supporting these 26 program projects including all supporting documents with specific attention to the variance explanations (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43, Atts. 1-3).[105] The Department notes that the program projects are less than $100,000, and under the Company's capital authorization policies do not require variance analyses or closure papers (Tr. 3, at 430-432). Thus, we will not exclude these projects from rate base based on the fact that the Company did not submit closure papers. We further note, however, that the Company did provide some variance analyses, which include cost overruns due to carryover work from prior years caused by severe weather events or outages, additional work written to train workers, and changes in project scope (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274;

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104 These consist of projects: C005432; C005563; C006642; C005439; C005441; C005444; C005449; C016492; C005475; C005480; C059664; C032015; C032016; C032018; C033822; C032272; C016120; C016121; C018594; CD00259; C025326; C027927; C032024; C032572; C033764; and C033765.

105 The Company provided variance explanations for fiscal years 2010 through 2015 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157).

NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157). While these explanations were provided for a group of similar program projects, not the individual program projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

We now turn to the 21 program projects for which the Company filed documentation on June 2, 2016.[106] As discussed above in Section VII.5.a.iii, the Department has granted the Attorney General's motion to strike these documents from the record. Therefore, we will evaluate each of these program projects based on information regarding these projects that was in the record prior to the close of hearings (Exhs. NG-JHP-3; NG-JHP-4).

The Department has reviewed the information supporting the Company's 21 program projects, as described above, with specific attention to the variance explanations (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The reasons for the variances include carryover work from prior years due to severe weather events or outages, additional work written to train workers, and changes in project scope (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8,

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106 These consists of projects: C005490; C005500; C014821; C021594; C022216; C022217; C005543; C005469; C028147; C025810; C032270; CD00017; C025619; C025813; C027898; C031398; C031774; C035584; C049352; and CD01258. Included in this number is one program project, C006138, for which the Company indicated it would be submitting a closure paper, but did not submit one with the June 2, 2016, filing. As explained below, however, we find that there is sufficient information in the record to evaluate the prudency of this project despite the absence of the closure paper.

at PGRM-1149-1157). The variance explanations for the 2013, 2014, and 2015 storm programs state that storm restoration programs are approved annually based on historic trends, that storm restoration work is mandatory, and that charges and adjustments from FY 2013 events such as Hurricane Sandy and the February Nemo storm were paid in FY 2014 (Exhs. NG-JHP-3(e), JLG-8, at PGRM-1190; NG-JHP-3(f), JHP-8, at PGRM-1155).

While these explanations were provided for a group of similar program projects, not the individual program projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

Additionally, as we stated above, we expect that National Grid will abide by its own capital authorization policies (i.e. preparing closure papers and reauthorization forms) as a reasonable means of maintaining adequate cost controls. Specifically, we note that the closure paper is the opportunity for the Company to reflect upon and document the lessons learned and ensure all close out activities have been performed (Exh. NG-JHP-1, at 17). However, given that National Grid did provide sufficient cost information and variance analyses for the projects at issue, we find that the Company's failure to timely compile and timely produce the closure papers is insufficient to support a finding that the Company failed to maintain adequate cost controls.

viii. Filing Requirements

The Company shall provide, as part of its next CIRM filing the following: (1) prefiled testimony; (2) for capital projects placed in service costing more than $50,000, project details including: project summary sheet, project cost summary, approval documents such as sanction/authorization papers and re-sanction/reauthorization documents, as required by the Company's capital authorization policies, work order asset detail reports, retirement reports, and direct/indirect reports; (3) closure papers, as required by the Company's capital authorization policies; (4) variance analyses for all projects over $50,000 consistent with the Company's capital authorization policies; (5) fiscal year variance analysis reports for its blanket and program projects; (6) a list of cancelled projects and a description of the disposition of the associated charges; and (7) new policies or updates to policies since the previous CIRM filing, affecting the Company's methods of: (i) approving delegations of authority, sanctioning and re-sanctioning funding projects, (ii) charging capital versus expense, (iii) determining when a capital asset is in danger of failure and should be replaced as part of a damage/failure blanket capital authorization, and (iv) instituting any other changes in accounting, allocation, and/or operational matters.

In its next CIRM filing, the Company also shall explain the cost variances between the final amount approved and the actual amount required to complete the project. For blanket and program projects that are not reauthorized throughout the year, the Company shall explain cost variances between the initial budgeted amount and the actual amount required to complete the project. Further, the Company shall provide fiscal year-end variance reports for blanket and program projects for the fiscal year ending in the calendar year under review and the fiscal year following the calendar year under review. The Company shall also describe any cost control efforts it has undertaken in response to the variances.

Additionally, the Department notes some inconsistencies with respect to when the Company requires reauthorization documentation, closure papers, and variance analyses. In order to review capital project documentation and understand the Company's complex capital project authorization process and blanket authorization policy, a significant amount of time during evidentiary hearings was devoted to exploring when closure papers and variance explanations are required (see Tr. 3, generally). Going forward, the Department directs the Company to provide all of its capital project documents in text searchable format with its CIRM filings. Moreover, the Department directs the Company to use consistent terminology, to the extent possible, and to ensure that policies are described consistently across documents (e.g., when closure papers are required for program projects). With the additional requirements for variance analyses directed above, the Company also shall document policies for performing variance analyses.

6. Conclusion

Based on all of the above findings, the Department approves the Company's proposed plant additions for inclusion in rate base. As a result of this decision, it no longer is necessary to review the prudency of the Company's capital additions in the following CapEx dockets: D.P.U. 10-79 (2009 CY additions), D.P.U. 11-60 (CY 2010 additions), D.P.U. 12-48 (CY 2011 additions); D.P.U. 13-84 (CY 2012 additions), D.P.U. 14-95 (CY 2013 additions), and D.P.U. 15-84 (CY 2014 additions). Accordingly, upon issuance of this Order, these dockets shall be closed.

C. 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 either generated internally by a 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; Boston Gas Company, D.P.U. 88-67 (Phase I) at 35 (1988).[107] 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 D.T.E. 98-51, at 15; 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. D.P.U. 11-01/D.P.U. 11-02, at 163, citing D.P.U. 10-114, at 108; 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, D.P.U. 08-35, at 38 (2009); D.T.E. 05-27, at 99-100. For these reasons, the Department requires all electric and gas companies serving more than 10,000

107 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, at 61,296 (1979). As a result, companies occasionally refer to the 45-day convention as the "FERC convention." D.P.U. 11-01/D.P.U. 11-02, at 150 n.81.

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 (Exh. NG-RRP-5). The Company proposed a cash working capital allowance of $68,019,916 using a net lead-lag factor of 5.70 percent, or 20.82 days (Exhs. NG-RRP-2, at 34 (Rev. 3); NG-RRP-8, at 6 (Rev. 3)).[108]

To determine its proposed cash working capital allowance, the Company first identified the following expense categories: (1) purchased power expense; (2) contract termination charges ("CTC");[109] (3) O&M expense; (4) transmission expense; (5) municipal taxes; (6) federal unemployment taxes; (7) state unemployment taxes; (8) FICA expense (both weekly and monthly);[110] (9) FICA and federal withholding (weekly and monthly); (10) state income tax withholding (weekly and monthly); and (11) incentive thrift (weekly and monthly) (Exh. NG-RRP-5, at 1 (Rev. 3)). The Company then determined a dollar-weighted period of time

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108 The Company reported a total distribution working capital requirement of $68,019,916 from a total dollar amount of $1,192,500,103, resulting in a CWC factor of 5.70 percent, which equates to 20.82 days (Exh. NG-RRP-2, at 34 (Rev. 3)).

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

110 FICA refers to the Federal Insurance Contributions Act. 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. §§ 3110(a) and (b). Also, FICA requires that the employer pay a matching employer share of (1) the Social Security tax and (2) the Medicare tax. 26 U.S.C. §§ 3111(a) and (b).

between the end date for the receipt of service from supplier and the payment date, producing expense lag factors as a percentage of total days in a calendar year ranging between a negative 1.59 percent for monthly state income tax withholding and 24.43 percent for state unemployment taxes (Exh. NG-RRP-5, at 8-24 (Rev. 3)).

Next, the Company developed separate revenue lags for both MECo and Nantucket Electric representing the time delay between the mailing of customers' bills and the receipt of the billed revenues from customers (Exh. NG-RRP-5, at 3 (Rev. 3)). 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 38.88 days associated with MECo's O&M expenses, 39.07 days associated with MECo's property and payroll taxes, and 23.16 days for Nantucket Electric's overall expenses (Exh. NG-RRP-5, at 3, 9, 26 (Rev. 3)). National Grid then added a billing lag of 1.41 days, representing the average lag from the date a meter is read to the date the bill is sent to the customer (Exh. NG-RRP-5, at 3 (Rev. 3)). The sums of the collection lags and service lags, represented as a percentage of the number of days in a calendar year, are 11.04 percent for MECo's O&M expenses, 11.09 percent for MECo's property and payroll taxes, and 6.73 percent for Nantucket Electric's overall expenses (Exh. NG-RRP-5, at 3, 9 (Rev. 3)).

The Company then subtracted the respective expense lag factors determined above from their respective revenue lag factors and then blended the results for both MECo and Nantucket, producing consolidated cash working capital factors for each expense category ranging between a negative 17.25 percent for federal unemployment taxes and 16.49 percent for municipal taxes (Exh. NG-RRP-5, at 2 (Rev. 3)). 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 CTC of $44,540,304 (Exh. NG-RRP-5, at 26, 30 (Rev. 3)).

As part of this analysis, National Grid computed a separate cash working capital factor associated with purchased power and CTC (Exh. NG-RRP-5, at 30 (Rev. 3)). To determine the cash working capital associated with purchased power, the Company determined a 19.78-day lag for purchased power and 3.05-day lag for CTC, representing 5.42 percent and 0.84 percent of a calendar year, respectively (Exh. NG-RRP-5, at 30 (Rev. 3)). Subtracting these percentages from MECo's revenue lag of 11.09 percent and Nantucket Electric's revenue lag of 6.73 percent as determined above produced purchased power cash working capital factors of 5.39 percent and 5.89 percent for MECo and Nantucket Electric, respectively, along with CTC cash working capital factors of 1.90 percent and 1.31 percent for MECo and Nantucket Electric, respectively (Exh. NG-RRP-5, at 30 (Rev. 3)). The Company then weighted the results for the two companies, producing an overall purchased power cash working capital factor of 5.34 percent and a CTC cash working capital factor of 1.88 percent (Exh. NG-RRP-5, at 1-2 (Rev. 3)). These cash working capital factors were then multiplied by the pro forma expense associated with these expense categories, producing cash working capital allowances of $56,248,188 associated with purchased power and a negative $54,067 for CTC (Exh. NG-RRP-5, at 1 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General does not challenge the Company's cash working capital calculations. However, she argues that if the Department allows National Grid to amortize its outstanding hardship protected account balances, it also must adjust the Company's cash working capital allowance to recognize the fact that those accounts receivable will no longer affect the cash working capital requirement because removing those accounts will change the revenue lag (Attorney General Brief at 56-57; Attorney General Reply Brief at 33).

According to the Attorney General, the Company seeks to recover $40,982,476 in hardship protected accounts,[111] representing an annualized $491,789,712 in monthly accounts receivable balances that the Company uses as an input in the revenue lag calculation (Attorney General Brief at 57). The Attorney General argues that this balance represents 15.65 percent of the $3,142,435,793 in total revenues used to compute the revenue lag calculation (Attorney General Brief at 57). The Attorney General notes that the Company concedes that the recovery of the hardship protected accounts will have an effect on the cash working capital allowance (Attorney General Reply Brief at 33). Thus, the Attorney General asserts that if the Department accepts the Company's proposal to amortize its hardship accounts receivable balance, the accounts receivable balance used in the lead-lag study should be reduced by 15.65 percent ($491,789,712 / $3,142,435,793) to recognize the elimination of these accounts receivable from the overall balance of accounts receivable (Attorney General Brief at 57; Attorney General Reply Brief at 33). The Attorney General estimates that this elimination will reduce the average revenue lag by 15.65 percent, or 6.11 days (39.07 days x 0.1565 = 6.11 days) (Attorney General Brief at 57).

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111 The $40,982,476 is based on National Grid's second revision to its revenue requirement calculation, the most recent available schedule at the time initial briefs were being prepared (Exh. NG-RRP-2, at 24 (Rev. 2). As noted in Section VIII.J.1 below, based on the Company's most recent revenue requirement calculations, the Company claims a total hardship protected account balance of $52,027,414 (Exh. NG-RRP-2, at 24 (Rev. 3)).

b. Company

National Grid argues that the Department should adopt the Company's lead-lag results and the Company's proposed cash working capital allowance (Company Brief at 21). Further, National Grid contends that the Attorney General's recommendation to reduce the Company's revenue lag for hardship protected accounts is baseless (Company Brief at 58; Company Reply Brief at 45-46). According to the Company, future recovery of these accounts receivable will be appropriately reflected in a future cash working capital study, and that attempting to recognize a pre-funding of these recoveries in the cash working capital study in this case is unwarranted and will understate the Company's true cash working capital requirement (Company Brief at 59; Company Reply Brief at 46). Therefore, National Grid asserts that the Department should reject the Attorney General's recommendation (Company Brief at 59; Company Reply Brief at 46).

3. Analysis and Findings

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. D.P.U. 87-260, at 22-23. Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164. In the event that the lead-lag factor is not below 45 days, a company will face a high burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

The Attorney General argues that the Department should adjust the Company's cash working capital allowance to account for any recovery of hardship protected account receivable balance over 360 days (Attorney General Brief at 56-57; Attorney General Reply Brief at 33). As discussed further in Section VIII.J.3 below, the Department has allowed the Company to recover $40,607,637, representing the test year balances of these hardship accounts. Further, we find that the Company incurred the costs to provide the services that the hardship protected account receivables represent and will recover those costs prospectively over the five-year amortization period. To the extent that this recovery affects the revenue lag component of National Grid's cash working capital allowances, the change in the revenue lag component will be incorporated in future cash working capital studies. Therefore, the Department finds no need to recalculate the Company's revenue lag.

The Company has included in its lead-lag study cash working capital of $264,963,146 associated with energy efficiency activities (Exhs. NG-RRP-8, at 6 (Rev. 3); NG-RRP-5, at 8 (Rev. 3)). The Green Communities Act[112] specifies that energy efficiency-related costs must be collected through a fully reconciling funding mechanism, and the Department has approved the Energy Efficiency Surcharge ("EES") for this purpose. G.L. c. 25, §§ 19(a), 21(b)(2)(vii); Guidelines, §§ 2.9, 3.2.1. Therefore, the Department finds that these costs should be recovered through the EES and not through base rates. Accordingly, the Department has excluded $264,963,146 in energy efficiency-related expenses from the calculation of the Company's cash

[112] St. 2008, c. 169. An Act Relative to Green Communities.

working capital allowance. The exclusion of these expenses results in a composite lead-lag factor of 5.67 percent (see Schedule 6 below). The Department has reviewed the evidence in support of the Company's lead-lag study and, apart from the inclusion of energy efficiency-related cash working capital, we conclude that the Company properly calculated the revenue lags and expense leads (Exhs. NG-RRP-2, at 4, 34 (Rev.3); NG-RRP-5 (Rev 3); DPU-24-6; DPU-24-7, DPU-24-8, DPU-24-9; DPU-24-10; DPU-24-11; AG-24-14 & Att.; AG-24-15; AG-24-17; Tr. 6, at 872-873). The recalculated lead-lag factor of 5.67 percent is equivalent to 20.7 days, and thus lower than the results under the 45-day convention (Exh. NG-RRP-2, at 34 (Rev. 3); see also NG-RRP-5, at 1 (Rev. 3)).

Application of the cash working capital factor of 5.67 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 $52,324,086 for the Company. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

D. Materials and Supplies

1. Introduction

The Department typically allows a company to include a representative level of its materials and supplies balance in rate base, which is determined using a 13-month average balance. Boston Edison Company, D.P.U. 19991, at 16 (1979); Housatonic Water Works Company, D.P.U. 86-235, at 3-4 (1987); High Wood Water Company, D.P.U. 1360, at 7-8 (1983); Western Massachusetts Electric Company, D.P.U. 1300, at 29 (1983). In its initial filing, National Grid reported a balance of $24,453,573 for its materials and supplies based on a test year-end balance (Exh. NG-RRP-2, at 30; Tr. 6, at 943-944). The Company later reduced the balance to $23,231,040 based on a 13-month average (Exh. NG-RRP-2, at 30 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Department precedent requires a utility to use the 13-month average of materials and supplies inventories when calculating its rate base (Attorney General Brief at 22). The Attorney General claims that the Company's 13-month average balance of materials and supplies inventories is $22,852,218, and she urges the Department to use this balance in determining the Company's rate base (Attorney General Brief at 22, citing Exh. AG-2-3, Att.).

b. Company

The Company agrees that its materials and supplies balance should be based on a 13-month average (Company Brief at 20; Company Reply Brief at 16). However, the Company contends that the Attorney General erred in her calculation, and that the correct 13-month average balance is $23,231,039 (Company Brief at 20; Company Reply Brief at 16).[113]

3. Analysis and Findings

Utilities keep on hand various materials and supplies for use in the course of normal operations. The Department's long-standing practice has been to include a representative level of a company's materials and supplies balance in rate base. D.P.U. 19991, at 16. The

[113] In its initial brief, the Company claimed that the 13-month average balance amounted to $22,473,396 (Company Brief at 20). The Company revised the amount to $23,231,039 in its reply brief (Company Reply Brief at 16). The Company's schedules show the amount at $23,231,040, a minor discrepancy likely due to rounding (Exh. NG-RRP-2, at 30 (Rev. 3)).

Department allows this adjustment to compensate a utility for the carrying cost associated with its inventory. Because of the month-to-month fluctuations in this account, a 13-month average balance is used. D.P.U. 86-235, at 3-4; D.P.U. 1360, at 7-8; D.P.U. 1300, at 29.

The Department has reviewed the Company's schedules and the monthly balances provided in the record (Exhs. NG-RRP-2, at 30 (Rev. 3); AG-2-3, Att.). Based on our review, we find that the Attorney General's calculation is based on the 13-month period from June 2014 through June 2015, whereas the Company's calculation is based on the 13-month period beginning July 2014 through July 2015 (see Exhs. NG-RRP-2, at 30 (Rev. 3); AG-2-3, Att.). In other words, the Attorney General's 13-month period includes the twelve months of the test year (July 2014 through June 2015) and the month preceding the test year, whereas the Company's 13-month period includes the twelve months of the test year and the month following the test year.[114]

The Department's 13-month convention requires the use of monthly balances for the twelve months of the test year, plus the month preceding the first month of the test year in order to calculate the 13-month average balance. See D.P.U 10-114, at 101-102 (approving the company's 13-month average that included the month preceding the test year); D.P.U. 86-235, at 3-4 (requiring the company to include the balance from the month preceding the test year in calculating the 13-month average balance). The Department, therefore, calculates the 13-month average balance of materials and supplies using the Company's monthly balances from June 2014 to June 2015, and we arrive at a total of $22,852,218 (see Exh. AG-2-3, Att.).

[114] Despite the representation provided by the Company regarding its calculations for the requested average in this matter, the Department notes that the Company's cost of service witness, when asked at the evidentiary hearings, calculated an average balance of $22,852,218 (Tr. 9, at 1438-1439).

Accordingly, the Department will further reduce the Company's proposed materials and supplies balance by $378,821.

E. Asset Retirement Obligations

1. Introduction

As part of its plant in service, the Company has included $332,000 in asset retirement obligations ("ARO") associated with general plant (Exh. NG-RRP-2, at 27, 30 (Rev. 3)).[115] An ARO represents estimated costs of future retirements that are not otherwise provided for in the net salvage factor used to derive the Company's depreciation accrual rates. D.P.U. 09-39, at 102. No party commented on brief about the Company's inclusion of AROs in its plant investment.

2. Analysis and Findings

The Uniform System of Accounts for Electric Companies ("USOA-Electric Companies"), codified as 220 C.M.R. § 51.00 et seq., specifies that AROs associated with general plant are to be booked to Account 399 (18 CFR Pt. 101, Balance Sheet Chart of Accounts, Electric Plant Instructions, Sec. 10(B)(2)).[116] Accounting requirements, however, do not necessarily dictate ratemaking treatment. D.P.U./D.T.E. 97-95, at 77; Massachusetts Electric Company, D.P.U. 92-78, at 79-80 (1992); Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979). The accounting systems prescribed by the Department, including the USOA-Electric

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115 The Company reported no accumulated depreciation associated with its ARO as of the end of the test year (Exh. NG-RRP-2, at 27 (Rev. 3)).

116 The Department has adopted the USOA-Electric Companies prescribed by FERC, with several modifications. 220 C.M.R. § 51.01(1). The applicable FERC system of accounts, entitled Uniform System of Accounts Prescribed For Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, are set forth at 18 CFR, Part 101.

Companies, represent systems whereby costs are categorized to provide the Department with information on utility operations and aid in the review of utility costs. The Department's ratemaking process takes into consideration many factors other than account balances. Therefore, the booking of a particular expense in accordance with the USOA-Electric Companies implies no judgment as to the reasonableness of that cost in a given instance, nor does it establish the per se treatment of that cost for ratemaking purposes. D.P.U./D.T.E 97-95, at 77; see also Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997).

The Company's AROs represent estimated future removal costs in the form of balance sheet entries that do not represent plant in service. D.P.U. 09-39, at 103-104; see also Western Massachusetts Electric Company, D.T.E. 05-9, at 13 (2005). National Grid's proposal, in effect, seeks not only recognition of its future retirement costs, but also recovery of carrying charges on those future costs. Regardless of the requirements of financial reporting, there is no basis to provide any regulated utility with a return on costs that have not yet been incurred. D.P.U. 09-39, at 103-104. Moreover, the Department is not persuaded that the net salvage factors used in the Company's depreciation study (see Section VIII.E below) are insufficient to recognize the cost of retiring the underlying assets.

Based on the foregoing analysis, the Department finds that the Company has failed to justify the inclusion of ARO in rate base. Accordingly, the Department reduces National Grid's proposed rate base by $332,000.

VIII. OPERATIONS AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach recognizes that the different components of compensation (i.e., 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.

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

National Grid's employee compensation program is known as the "Total Rewards Program" (Exh. NG-MPH-1, at 6). The Total Rewards Program encompasses fixed pay, variable pay, medical and dental insurances, life insurance, a 401(k) retirement savings plan, and pensions and post-retirement benefits (Exh. NG-MPH-1, at 6).

2. Non-Union Wages

a. Introduction

During the test year, National Grid booked $69,182,833 in payroll expense for non-union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $6,961,426 in payroll expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated, respectively, $61,428,586 and $792,821 to the Company's test year payroll expense (Exh. NG-RRP-2, at 9-10).[117]

The Company initially proposed an increase to non-union payroll expense of $3,710,260 based on: (1) a non-union wage increase of 3.5 percent effective July 1, 2016; and (2) the inclusion of 27 approved non-union NGSC positions vacated during the test year and unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 28-29; NG-RRP-2, at 8-10; NG-MPH-1, at 8-9; DPU-8-20, Att. at 1).[118] Based on revisions made during the proceeding, National Grid now proposes to increase non-union payroll expense by $1,965,104 (Exh. NG-RRP-2, at 8-10 (Rev. 3)). This change represents a reduction to the 2016 non-union wage increase from 3.5 percent to 3.2 percent, a reduction to the approved non-union NGSC positions from 27 to 25, and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 8-10 (Rev. 3); NG-MPH-Rebuttal-1, at 8; NG-MPH-Rebuttal-3; NG-RRP-Rebuttal-1, at 15; DPU-8-20; AG-22-1, Att. at 1). The non-union wage increases were determined based on an industry compensation assessment performed by Towers Watson on

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

118 Proposed adjustments for all approved positions are addressed in Section VIII.A.4 below.

behalf of the Company, projected increases in non-union base salaries, and an historical comparison of non-union base wage increases to union base wage increases (Exhs. NG-MPH-1, at 8-13; NG-MPH-2; NG-MPH-7; NG-MPH-8).

b. Positions of the Parties

i. Attorney General

The Attorney General's comments regarding non-union wage adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i below (Attorney General Brief at 24-25).

ii. Company

The Company argues that its non-union compensation is market competitive and that the cost of service includes known and measurable changes occurring before the mid-point of the rate year (Company Brief at 94). Specifically, National Grid claims that the Towers Watson analyses demonstrate that the salary range for each of its six employee bands is competitive with the median market rate (Company Brief at 96, citing Exh. NG-MPH-1, at 6-7, 9, 12). Further, the Company argues that the aggregate non-union increase of 3.2 percent scheduled to take effect on July 1, 2016, is based on market studies currently available to National Grid and closely aligned with the relevant markets (Company Brief at 97, citing Exhs. NG-MPH-1, at 9, 12-13; NG-MPH-7; DPU-8-26). The Company asserts that its non-union salary increase is reasonable and should be approved by the Department for inclusion in the Company's cost of service (Company Brief at 97).

c. Analysis and Findings

The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that: (1) non-union salary increases are scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, that there is an express commitment by management to grant the increase; (3) there is an historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. D.P.U. 85-266-A/85-271-A at 107; 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).

The Company provided a management commitment letter stating that a 3.2 percent payroll increase for non-union Company employees would take place on July 1, 2016 (Exh. NG-MPH-Rebuttal-3). Additionally, the Company provided a ten-year history of union and non-union wage increases (Exh. NG-MPH-8). Between 2006 and 2015, annual union wage increases were between 2.5 percent and 3.25 percent, and non-union wage increases were between 0.43 percent and 3.9 percent (Exh. NG-MPH-8). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

Finally, with respect to the reasonableness of the non-union wage increase, the Company sets total cash compensation equal to the median of the marketplace (Exh. NG-MPH-1, at 9). Specifically, National Grid participates in an annual market study performed by an independent third-party vendor, Towers Watson, and, using that study, compares overall pay of certain benchmark positions to the 50th percentile of overall pay for comparable jobs in similarly sized companies (Exh. NG-MPH-1, at 9). The Towers Watson study concluded that the Company's non-union compensation levels are competitive against similarly sized energy services companies (those with revenues greater than $6 billion) as well as total sample energy services companies (Exh. NG-MPH-2, at 5). The Department determines that National Grid's review of industry compensation data is sufficient to confirm the reasonableness of its non-union salary levels. See D.P.U. 10-55, at 245; D.T.E. 05-27, at 109; D.T.E. 02-24/25, at 94.

Based on the above, we find that National Grid has demonstrated that: (1) there is an express management commitment to grant a 3.2 percent non-union wage increase; (2) there is an historical correlation between union and non-union payroll increases; and (3) the non-union wage increases are reasonable. Accordingly, we allow the Company's adjusted non-union payroll expense, subject to our findings below on staffing levels.

3. Union Wages

a. Introduction

During the test year, National Grid booked $72,861,689 in payroll expense for union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $57,915,195 in payroll expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $11,965,079 and $2,981,415, respectively, to the Company's test year payroll expense (Exh. NG-RRP-2, at 9-10).

The Company initially proposed an increase to test year union payroll expense of $7,285,812 based on: (1) Company and NGSC union wage increases of 2.5 percent effective May 12, 2016; (2) affiliated companies' union wage increases of 2.0 percent and 2.5 percent effective April 1, 2016 and May 12, 2016, respectively; (3) the inclusion of five approved union Company positions vacated during the test year and unfilled as of June 30, 2015; and (4) nine approved union NGSC positions vacated during the test year and unfilled as of June 30, 2015[119] (Exhs. NG-RRP-1, at 27-29; NG-RRP-2, at 8-10; NG-MPH-1, at 14-15; DPU-8-19, Att.; DPU-8-20, Att. at 1). Based on revisions made during the proceeding, National Grid now proposes to increase union payroll expense by $7,001,070 (Exh. NG-RRP-2, at 8-10 (Rev. 3)). This change represents a reduction to the total approved union positions from 14 to twelve and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 8-10 (Rev. 3); DPU-8-19, Att.; DPU-8-20; AG-22-1, Att. at 1). The union wage increases were determined by currently effective collective bargaining agreements (Exhs. NG-MPH-1, at 14-15; AG-1-42, Atts. 1-17).

b. Positions of the Parties

i. Attorney General

The Attorney General's comments regarding union wage adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i, below (Attorney General Brief at 22-25).

ii. Company

The Company states that its union compensation is market competitive and that the cost of service includes known and measurable changes occurring before the mid-point of the rate year (Company Brief at 94). Specifically, National Grid argues that the analysis provided demonstrates that the hourly rates paid to its union employees are within the range of

119 Proposed adjustments for all approved positions are addressed in Section VIII.A.4 below.

surrounding utilities (Company Brief at 98, citing Exh. NG-MPH-9).[120] The Company also claims that it has illustrated the reasonableness of union wage levels (Company Brief at 98). Further, National Grid contends that the proposed union wage increases are based on currently effective collective bargaining contracts and, therefore, satisfy the Department's known and measurable requirement for post-test year union wage adjustments (Company Brief at 95, 97). Based on these considerations, the Company asserts that its union compensation costs are reasonable and should be approved by the Department for recovery (Company Brief at 97).

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 date of the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted before April 1, 2017, the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. NG-MPH-1, at 14-15; AG-1-42, Atts. 1-17). Further, because the union payroll increases are based on signed collective bargaining agreements, the Department finds that the proposed increases are known and measurable (Exh. AG-1-42, Atts. 1-17). Finally, with respect to the reasonableness of the union

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[120] For seven positions, the Company compared its union wage pay levels with pay levels for nine other New England electric utilities (seven investor owned and two municipals), calculating median, average, and maximum pay rates for each position (Exh. NG-MPH-9).

wage increases, National Grid submitted a comparison of its union salaries to utilities throughout New England (Exhs. NG-MPH-1, at 15; NG-MPH-9). National Grid's hourly pay rates are comparable to those of other utility companies in the region for the selected union job titles (Exh. NG-MPH-9). Thus, we find that the Company has demonstrated the reasonableness of its union wage increases.

Based on the above, the Department finds that National Grid's union wage increases (1) take effect before the midpoint of the first twelve months after the rate increase; (2) are known and measurable; and (3) are reasonable. Accordingly, we allow the Company's proposed union payroll adjustments, subject to our findings below on staffing levels.

4. Employee Staffing Levels

a. Introduction

National Grid proposed adjustments for changes in staffing levels after the test year, calculating the wage expense based on the employee complement as of June 30, 2015 (Exh. NG-RRP-1, at 27). The Company initially proposed to include $362,627 in wages and salaries for five approved union Company positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 27; NG-RRP-2, at 8). Additionally, the Company initially proposed to include $3,060,864 in wages and salaries for nine approved union NGSC positions and 27 approved non-union NGSC positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 28-29; NG-RRP-2, at 9; DPU-8-20, Att.). Based on revisions made during the proceeding, National Grid now proposes to include $267,010 in wages and salaries for four approved union Company positions (Exhs. NG-RRP-2, at 8 (Rev. 3); NG-RRP-Rebuttal-1, at 36). The Company also proposes to include $544,618 in wages and salaries for eight approved union NGSC positions and 25 approved non-union NGSC positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-2, at 9 (Rev. 3); NG-RRP-Rebuttal-1, at 15; AG-22-1, Att. at 1). These changing in staffing levels, and the corresponding decreases in expenses, were the result of position cancellations and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 9 (Rev. 3); DPU-8-20; AG-22-1, Att. at 1).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject the Company's proposal to include four Company and 33 NGSC vacant positions in its cost of service, including proposed increases to payroll expense, employee benefits costs, and payroll taxes (Attorney General Brief at 22-24). Specifically, the Attorney General claims that the Company has not established that the filling of the vacant positions is outside the normal ebb and flow of its workforce complement (Attorney General Brief at 23). Further, the Attorney General contends that the Company has provided no evidence that the employee level as of June 30, 2015, which does not include the vacant positions, is abnormal or unreflective of typical vacancy conditions (Attorney General Brief at 25). Thus, the Attorney General asserts that all four Company and 33 NGSC positions should be excluded from the cost of service in this case (Attorney General Brief at 23 and 25). The Attorney General recommends a pro forma wage and salary expense reduction of $145,272 to eliminate the four proposed Company positions, as well as reductions of $38,335 and $10,825 in associated employee benefits expenses and payroll taxes, respectively

(Attorney General Brief at 24, citing Exh. AG-DJE-Rebuttal-1, Sch. DJE-1). Additionally, the Attorney General recommends a pro forma wage and salary expense reduction of $374,509 to eliminate the 33 proposed NGSC positions, as well as reductions of $75,887 and $27,906 in associated employee benefits expenses and payroll taxes, respectively (Attorney General Brief at 25, citing Exhs. AG-DR-Rebuttal-1, at 4; NG-RRP-Rebuttal-2, column NG(c)).

ii. Company

The Company argues that its proposal to include four Company and 33 NGSC positions in the cost of service is narrower than the Attorney General suggests, is backed by Department precedent, and should be approved by the Department (Company Brief at 70-71). National Grid agrees with the Attorney General that is it reasonable to assume that the Company and NGSC will always have vacant positions (Company Brief at 70). However, the Company states that it does not seek to make adjustments for all Company and NGSC positions that were vacant as of June 30, 2015, but rather a narrow subset of those positions (Company Brief at 70). The Company maintains that its proposal covers only those Company and NGSC positions that were filled during the test year, were vacant as of June 30, 2015, and were filled prior to the filing of the instant case or prior to the expiration of this proceeding (Company Brief at 70). Additionally, National Grid contends that its request is similar to one previously approved by the Department for New England Gas Company (n/k/a Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities) (Company Brief at 71, citing D.P.U. 10-114, at 135). National Grid argues that New England Gas Company's proposal to include costs associated with a position filled during the 2009 test year, vacated as of 2010, and then filled by a temporary employee is analogous to the Company's proposal in this proceeding (Company Brief at 71). Further, National Grid argues that the Department's approval of New England Gas Company's proposal renders the Company's own wage and salary adjustments appropriate (Company Brief at 71). Therefore, the Company asserts that the Department should approve the proposed adjustments (Company Brief at 71).

c. Analysis and Findings

Employee staffing levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. Massachusetts-American Water Company D.P.U. 88-172, at 12 (1989); D.P.U. 1270/1414, at 16-17. In recognition of this variability, the Department generally determines payroll expense on the basis of test year employee levels, unless there has been a significant post-test year change in the number of employees that falls outside the normal ebb and flow of a company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

National Grid asserts that the Department's approval of New England Gas Company's proposal to include a vacancy is analogous to its own proposal to include 37 vacancies (Company Brief at 71, citing D.P.U. 10-114, at 135). In fact, New England Gas Company's proposal was different in two significant ways. First, in D.P.U. 10-114, the position proposed for inclusion in the pro forma cost of service was not vacant at the end of the 2009 test year, while the positions in the instant case were vacant at the end of National Grid's test year. D.P.U. 10-114, at 135. Therefore, the positions in the instant case, unfilled on June 30, 2015, are rightfully excluded from an employee complement taken on that date. Additionally, New England Gas Company had removed temporary employee costs from 175 contract labor accounts, and the purpose of the proposed adjustment was to move the temporary employee cost into that company's pro forma payroll expense account. D.P.U. 10-114, at 135. Therefore, the

Department's decision in D.P.U. 10-114 allowed a proposal to move incurred, known, and measurable salary costs to the correct, permanent payroll expense account. This proposal is fundamentally different from National Grid's proposal in the instant case to increase the test year-end employee complement and associated payroll expense by 37 vacant positions.

Additionally, the Company argues that the 37 positions it proposes to include in its pro forma cost of service are appropriate because these positions were in place during the test year, temporarily vacated as of June 30, 2015, and filled before the expiration of this case (Company Brief at 70). The selection of the test year, however, is largely a matter of a distribution company's choice. See D.P.U. 07-50-A at 51. Of its own volition, the Company selected the twelve-month period ending June 30, 2015, as the test year (see Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6). Subsequently, National Grid annualized base wages of its employee complement as of June 30, 2015 (Exh. NG-RRP-1, at 27). Any changes to the employee complement after this date would be considered a post-test year change, including those positions vacated as of June 30, 2015 and filled thereafter. Therefore, the Company must demonstrate that the filling of the 37 positions constitutes a significant post-test year change above and beyond the normal ebb and flow of employment levels in order for the Department to grant the proposed adjustments to payroll expense. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

The Company made no explicit effort to demonstrate that the post-test year changes to employee levels were significant or outside the normal ebb and flow of the workplace. Nonetheless, the Department has analyzed the impact of filling the proposed vacancies on payroll expense levels as well as employee staffing levels. The four proposed union vacancies' wages and salaries represent 0.46 percent of total test year union payroll O&M expense (Exh. NG-RRP-2, at 8 (Rev. 3)). The Company's share of the eight proposed union and 25 proposed non-union vacancies' wages and salaries represents 0.82 percent and 0.73 percent of the Company's shares of total union and non-union test year NGSC payroll O&M expense, respectively (Exh. NG-RRP-2, at 9 (Rev. 3)). These amounts, both less than one percent, do not represent significant changes to test year payroll expense. D.P.U. 90-121, at 80-81. Alternatively, using monthly employee levels, the four proposed union vacancies constitute 0.37 percent of the 1,070 union Company employees present in the last month of the test year (Exh. DPU-8-21, Att.). The eight proposed union and 25 proposed non-union vacancies comprise 0.57 percent of the 1,405.5 union and 0.66 percent of the 3,782 non-union NGSC employees present in the last month of the test year (Exh. DPU-8-22, Att.). These amounts, both less than one percent, also do not represent significant changes to test year employee levels.

Based on evidence provided in the instant case, the Department concludes that the 37 proposed vacancies do not constitute a significant post-test year change. Thus, the Department rejects the portion of the proposed salary and wage adjustments related to the approved positions vacated during the test year. The Department reduces the Company's proposed cost of service by $526,169.[121] In accordance with the above staffing level

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[121] Of this amount, $145,273 reduces proposed adjustments to MECo and Nantucket Electric payroll expense and $380,896 reduces proposed adjustments to the Company's share of NGSC payroll expense. The two reductions are further broken down as follows: (1) $267,010 proposed union vacancy salaries * 1.025 union wage increase * 0.5308 O&M percentage of base wages = $145,273 reduction to proposed MECo and Nantucket Electric payroll expense adjustment; (2) ($97,542 proposed union vacancy salaries * 1.025 union wage increase * 0.5577 O&M percentage of base wages = $55,756) + ($447,076 proposed non-union vacancy salaries * 1.032 non-union wage increase * 0.7047 O&M percentage of base wages = $325,140) = $380,896 reduction to proposed

adjustments, concordant adjustments to health care expense will be addressed below. Further, concordant adjustments to payroll tax expense, group insurance expense, and employee thrift expense will be addressed in the payroll taxes section, below.

5. Variable Compensation

a. Introduction

National Grid's variable compensation program is called the "Annual Performance Plan" (Exh. NG-MPH-1, at 17). There are three components to the variable pay program: (1) performance metrics tied to overall Company financial results, including earnings per share and ROE; (2) performance metrics based on safety, reliability, customer responsiveness, cost competitiveness, and stewardship (collectively referred to as "Elevate targets"); and (3) performance metrics based on individual objectives (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-6, at 1). The Company's non-union employees are classified into six salary categories ("Salary Bands") (see Exh. NG-MPH-1, at 19-20). Salary Band A consists of National Grid's most senior executives, Salary Bands B and C includes officers/directors, and Salary Bands D through F include managers, analysts, and all other non-union Company employees (Exh. NG-MPH-1, at 19-20). Each of the six Salary Bands, as well as all union employees, are assigned a particular combination of the above three components to arrive at the total Annual Performance Plan award (Exh. NG-MPH-1, at 19, 21). An eligible employee's maximum Annual Performance Plan award ranges from five percent to 40 percent of the same year's base wages, and varies by Salary Band (Exhs. NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-6, at 1).

Company share of NGSC payroll expense adjustment (see Exh. NG-RRP-2, at 8-9 (Rev. 3)).

For employees in Salary Bands A, B, and C, 20 percent of the Annual Performance Plan award is based on attaining Elevate targets, 40 percent is based on attaining financial metrics, and 40 percent is based on attaining employee-specific goals (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1). For employees in Salary Bands D, E, and F, 50 percent of the Annual Performance Plan award is based on attaining Elevate targets and 50 percent is based on attaining employee-specific objectives (Exhs. NG-MPH-1, at 19; NG-MPH-6, at 1). In the case of all union employees, 100 percent of the Annual Performance Plan award is based on attaining Elevate targets (Exh. NG-MPH-1, at 19).

During the test year, the Company booked $10,638,165 in variable compensation for non-union personnel (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $491,622 in variable compensation expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $9,737,387 and $409,156, respectively, to the Company's test year variable compensation expense (Exh. NG-RRP-2, at 9-10). During the test year, National Grid also booked $2,349,884 in variable compensation for union personnel (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $1,992,598 in variable compensation expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $230,535 and $126,751, respectively, to the Company's test year variable compensation expense (Exh. NG-RRP-2, at 9-10).

National Grid initially proposed to increase non-union and union variable compensation by $346,642 and $56,160, respectively, to recognize the proposed 3.5 percent and 2.5 percent increases to test year wages (Exh. NG-RRP-2, at 8-10). Based on revisions made during the proceeding, the Company now proposes to increase non-union and union variable compensation by $316,929 and $56,160, respectively (Exh. NG-RRP-2, at 8-10 (Rev. 3)). As noted above, this change results from a reduction to the 2016 non-union wage increase from 3.5 percent to 3.2 percent (Exhs. NG-RRP-2, at 8-10 (Rev. 3); NG-MPH-Rebuttal-1, at 8; NG-MPH-Rebuttal-3). Additionally, National Grid's proposed cost of service removes variable compensation for Salary Band A employees, the Company's most senior executives (Exh. NG-MPH-1, at 20).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should remove the financial component of incentive compensation costs from National Grid's cost of service (Attorney General Brief at 31). The Attorney General claims that the Department has made it clear that if financial goals are used in incentive plans, they should be used as a threshold component only (Attorney General Brief at 31). Further, she notes that while the Company's efforts to reduce the portion of variable pay tied to meeting financial goals are commendable, the record shows that 40 percent of the potential incentive plan awards for Salary Bands B and C employees are based on financial targets such as earnings per share and ROE (Attorney General Brief at 34). The Attorney General maintains that the goals of earnings per share and ROE clearly focus on shareholder interests (Attorney General Brief at 35). Thus, she argues that the costs associated with the attainment of such goals should be excluded from costs charged to Massachusetts ratepayers (Attorney General Brief at 35). Specifically, she recommends reducing the Company's pro forma cost of service by $847,532 (Attorney General Brief at 35). The recommended reduction includes $756,422 to remove variable pay associated with achieving financial metrics and $91,110 in concordant adjustments to group insurance, employee thrift, and payroll taxes (Attorney General Brief at 35).

ii. Company

The Company argues that the costs of its incentive compensation plan are reasonable and that the plan itself is reasonably designed to encourage good employee performance (Company Brief at 100). National Grid contends that excluding the entire variable pay component for its most senior executives, as it did in D.P.U. 09-39, contributes to the reasonableness of its overall incentive compensation cost level included in rates (Company Brief at 100). The Company also claims that the current incentive compensation structure is similar to plans previously approved by the Department in which a higher percentage of non-union variable pay was tied to meeting financial performance objectives (Company Brief at 101, citing D.P.U. 10-55; D.P.U. 09-39).

Nonetheless, National Grid recounts several steps it took to modify its variable pay program to better align with the Department's expectations following the Department's decision in D.P.U. 10-55 (Company Brief at 101). These steps include reducing the amount of variable pay tied to financial performance from 60 percent for Band A and B employees and 50 percent for Band C employees to 40 percent across all employees in Bands A through C, eliminating financial targets altogether for employees in Bands D through F, and adding customer satisfaction, safety and reliability targets for its officers and directors (Company Brief at 101). Finally, with respect to the financial metrics themselves, the Company states that it replaced line of business financial targets with earnings per share and ROE goals to emphasize quality of financial management, particularly in the area of internal cost containment (Company Brief at 101). Finally, National Grid claims that implementing cost containment measures, in pursuit of a ROE goal, will delay base rate cases or limit the impact of those cases and thus will benefit customers (Company Brief at 102).

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if (1) the expenses are reasonable in amount, and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; 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.

The Department must first determine whether the costs associated with National Grid's Annual Performance Plan are reasonable in amount. First, the Company does not seek to recover variable pay for its most senior executives (Exh. NG-MPH-1, at 20). Next, the Company has provided the 2015 results of a Towers Watson assessment that compared total cash compensation, defined as base pay plus any incentive or variable compensation, to the median of the marketplace (Exh. NG-MPH-2, at 5). The Towers Watson study concluded that National Grid's non-union compensation levels are competitive against similarly sized energy services companies (those with revenues greater than $6 billion) as well as total sample energy services companies (Exh. NG-MPH-2, at 5). Based on our review of this evidence, the Department finds that National Grid has demonstrated that its incentive compensation costs are reasonable in amount. See D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

The Department must next determine whether the Company's Annual Performance Plan is reasonable in design. A portion of the Annual Performance Plan expense is tied to meeting financial metrics such as earnings per share and ROE (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1). The Attorney General argues that the Department should deny recovery of variable compensation related to financial metrics because the Company chose to continue to make financial goals components of the plan design upon which payouts are based, despite what the Attorney General maintains is the Department's clear parameters in a decision involving the Company's affiliate, Boston Gas Company (Attorney General Brief at 31, citing D.P.U. 10-55, at 253-254).

The Department has articulated its expectations on the use of financial targets in variable compensation plans and the burden to justify recovery of such costs in rates. D.P.U. 15-80/D.P.U. 15-81, at 115-116; D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Specifically, where companies seek to include financial goals as a component of incentive compensation design, the Department expects to see the attainment of such goals as a threshold component, with job performance standards designed to encourage good employee performance (e.g., safety, reliability, customer satisfaction goals) used as the basis for determining individual incentive compensation awards. D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Companies that nonetheless wish to maintain financial metrics as a component of the formula used to determine individual incentive compensation must be prepared to demonstrate direct ratepayer benefit from the attainment of these goals or risk disallowance of the related incentive compensation costs. D.P.U. 13-90, at 83; D.P.U. 11-01/D.P.U. 11-02, at 193; D.P.U. 10-70, at 106; D.P.U. 10-55, at 253-254.

National Grid's financial metrics do not operate as a threshold component, but rather are a direct component of overall incentive compensation plan design (Exh. NG-MPH-1, at 19-20). While we acknowledge the Company's decisions to reduce the portion of variable pay tied to financial metrics and to introduce customer satisfaction, safety, and reliability targets for officers and directors, the financial metrics still represent 40 percent of the incentive compensation payment calculation for employees in Salary Bands A, B, and C (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-Rebuttal-1, at 6). Thus, National Grid must demonstrate direct ratepayer benefit from the attainment of earnings per share and ROE goals to recover this portion of incentive compensation costs from ratepayers. D.P.U. 10-55, at 253-254. The Company acknowledges this recovery standard and contends that customers benefit from cost containment measures that may be implemented in the pursuit of ROE and earnings per share goals, but has made no substantive demonstration of this claim (Exhs. NG-MPH-Rebuttal-1, at 5-6; DPU-8-28). Therefore, consistent with Department precedent, the Department finds that National Grid has failed to demonstrate that the financial metrics components of its incentive compensation plan are reasonably designed to encourage good employee performance and result in direct ratepayer benefits.

Accordingly, the Department reduces National Grid's proposed cost of service by $754,230[122] to remove the portion of the Company's incentive compensation expense attributable to the earnings per share and ROE measures (see Exh. DPU-8-29). In recognition of the above variable compensation expense adjustments, concordant adjustments to payroll tax expense will be addressed below.

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122 The Department's adjustment incorporates the non-union salary update of 3.2 percent provided in Exhibit NG-RRP-2, at 8-10 (Rev. 3).

B. Payroll Taxes

1. Introduction

During the test year, National Grid booked $10,584,314 in adjusted payroll taxes after removing $163,969 in qualified storm costs eligible for recovery through the storm fund (Exh. NG-RRP-2, at 29). The Company originally proposed to increase its cost of service by $819,226 to recognize the additional payroll taxes associated with its pro forma wage and salary expense (Exhs. NG-RRP-1, at 39; NG-RRP-2, at 29). Based on revisions made during the proceeding, National Grid now proposes to increase payroll tax expense by $388,624 (Exh. NG-RRP-2, at 29 (Rev. 3)). This change represents the removal of energy efficiency-related payroll taxes and the application of wage-based caps to several payroll tax categories (Exhs. NG-RRP-2, at 29 (Rev. 3); AG-20-16; Tr. 9 at 1420-1421; RR-DPU-2).

2. Positions of the Parties

a. Attorney General

As stated in Section VIII.A.4.b.i above, the Attorney General argues that the Department should reject National Grid's proposal to include four Company and 33 NGSC vacant positions in its cost of service (Attorney General Brief at 24-25). The Attorney General subsequently recommends associated payroll, payroll tax, and other employee compensation-related expense reductions (Attorney General Brief at 24-25). The Attorney General recommends a payroll tax expense reduction of $38,731, consisting of $10,825 in payroll taxes associated with the four Company vacant positions, and $27,906 in payroll taxes associated with the 33 NGSC vacant positions (Attorney General Brief at 24-25, citing Exhs. AG-DJE-Rebuttal-1, Sch. DJE-1; NG-RRP-Rebuttal-2, column NG(c)).

b. Company

National Grid argues that it calculated the change in payroll tax in proportion to its proposed labor and incentive compensation adjustments (Company Brief at 93, citing Exhs. NG-RRP-1, at 39; NG-RRP-2, at 29 (Rev. 2)). The Company claims that it increased payroll tax expense by 6.31 percent to account for a 6.31 percent increase in rate year salaries and wages as compared to test year salaries and wages (Company Brief at 93). National Grid argues that the Department should approve the Company's proposed adjustments to taxes other than income taxes (Company Brief at 93).

3. Analysis and Findings

The Department has examined the record related to the Company's payroll tax calculations (e.g., Exhs. NG-RRP-2, at 29 (Rev. 3); DPU-8-31; AG-20-16; Tr. 1, at 108-117; Tr. 9, at 1420-1421; RR-DPU-1; RR-DPU-2), and we find that three revisions must be made. First, the Department revises the percentage change in rate year salaries and wages used to calculate the initial payroll tax adjustment (Exh. NG-RRP-2, at 29, line 4 (Rev. 3)). Second, the Department revises the percentage of rate year payroll expense subject to increased Social Security tax used to calculate the final payroll tax adjustment (RR-DPU-1, Att. at 183; RR-DPU-2, Att.). Third, the Department will make necessary revisions to the Company's group insurance expense and employee thrift expense. These are explained in further detail below.

First, based on staffing level and incentive compensation expense adjustments discussed in Sections VIII.A.4.c and VIII.A.5.c above, the Department reduces the Company's most recent rate year O&M salaries and wages figure by $1,280,399.[123] This reduction yields a revised percentage change in rate year salaries and wages of 5.41 percent.[124] Second, based on the disallowance of 37 vacancies discussed in Section VIII.A.4.c above, the Company's most recent calculation of rate year labor subject to payroll tax must not include these vacancies' salaries and wages (RR-DPU-1, Att. at 183). Removing these salaries and wages yields a revised percentage of rate year payroll expense subject to increased Social Security tax of 54.8 percent.[125] Applying these two changes yields a final payroll tax expense adjustment of $332,952.[126] Therefore, the Department reduces the Company's proposed cost of service by $55,672 ($388,624 - $332,952).

Finally, in accordance with the above revision to the percentage change in rate year salaries and wages used to calculate the payroll tax adjustment, the Department makes necessary revisions to group insurance expense and employee thrift expense adjustment calculations that

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123 This amount includes a $526,169 staffing level reduction to payroll expense and a $754,230 variable compensation reduction to payroll expense (see also Exh. DPU-8-29).

124 (($151,010,695 proposed rate year O&M wages - $1,280,399 Department reduction to rate year O&M wages) - $142,044,523 test year O&M wages)/$142,044,523 = 0.0541 percentage change in rate year O&M wages (see Exh. NG-RRP-2, at 29, line 8-13 (Rev. 3)).

125 $813,257,570 total rate year labor below SS-FICA cap /$1,482,901,070 total rate year SS-FICA taxable labor = 0.548 proportion of rate year labor subject to tax increase (see RR-DPU-1, Att. at 183).

126 ($7,773,787 adjusted test year FICA expense * 0.0541 percentage change in rate year O&M wages * 0.548 proportion of rate year labor subject to tax increase = $230,646) + ($1,818,063 adjusted test year Medicare expense * 0.0541 percentage change in rate year O&M wages = $98,357) + ($68,744 adjusted test year NY Commuter Tax * 0.0541 percentage change in rate year O&M wages = $3,719) + ($4,236 adjusted test year Other payroll tax expense * 0.0541 percentage change in rate year O&M wages = $229) = $332,952 final payroll tax adjustment (see Exh. NG-RRP-2, at 29, line 5d (Rev. 3); RR-DPU-1, Att. at 183; RR-DPU-2).

use the percentage change figure. Using the 5.41 percentage change figure to increase adjusted test year expense, the Department finds that National Grid's final group insurance expense adjustment is equal to $74,455.[127] The Company proposed an adjustment to group insurance expense of $83,378 (Exh. NG-RRP-2, at 12 (Rev. 3)). Therefore, the Department reduces the Company's proposed cost of service by $8,923 ($83,378 - $74,455). Further, the Department increases National Grid's adjusted test year employee thrift expense by 5.41 percent to determine the final employee thrift expense adjustment of $259,221.[128] The Company proposed an adjustment to employee thrift expense of $302,492 (Exh. NG-RRP-2, at 13 (Rev. 3)). The Department thus reduces the Company's proposed cost of service by $43,272 ($302,492 - $259,221).

C. Medical and Dental Expenses

1. Introduction

National Grid's health care plans are self-insured (Exh. NG-MPH-1, at 23). National Grid booked $18,946,518 in test year medical and dental costs (Exh. NG-RRP-2, at 11). Of that amount, MECo and Nantucket Electric directly incurred $8,450,973 in health care expense (Exh. DPU-8-2). NGSC and affiliated companies allocated $10,260,676 and $234,869 to the Company's test year medical and dental expense, respectively (Exh. DPU-8-2). The Company

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127 ($1,466,588 adjusted test year group insurance expense * 0.0541 percentage change in rate year O&M wages = $79,331) – $4,877 Company adjustment for management program = $74,455 final group insurance expense adjustment (see Exh. NG-RRP-2, at 12 (Rev. 3)).

128 $4,792,161 adjusted test year thrift expense * 0.0541 percentage change in rate year O&M wages = $259,221 final thrift expense adjustment (see Exh. NG-RRP-2, at 13 (Rev. 3)).

initially proposed a decrease to test year medical and dental expense of $250,830 based on 2016 working rates,[129] which also includes adjustments for five proposed Company positions and 36 proposed NGSC positions (Exhs. NG-RRP-1, at 29-30; NG-RRP-2, at 11). Based on revisions made during the proceeding, National Grid now proposes to decrease test year medical and dental expense by $263,968 (Exh. NG-RRP-2, at 11 (Rev. 3)). This change reflects a reduction to the total proposed Company positions from five to four, and a reduction to the total proposed NGSC positions from 36 to 33 (Exh. NG-RRP-2, at 11 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General's comments regarding medical and dental expense adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i above (Exhs. AG-DJE-1, at 6-7; AG-DR-1, at 8; AG-DJE-Rebuttal-1, at 2-3; AG-DR-Rebuttal-1, at 4).

b. Company

National Grid argues that its medical and dental costs are reasonable in amount (Company Brief at 104). Further, the Company contends that the Towers Watson studies included in the initial filing illustrate that the health care plans offered to non-union and union employees are close to and above the market medians, respectively (Company Brief at 104, citing Exh. NG-MPH-1, at 22). Additionally, National Grid claims that it has taken several steps

129 Working rates are Towers Watson's, the Company's healthcare consultant, estimates of plan costs for the upcoming plan year. The working rates are based on enrollment data, at least twelve months of historical claims experience, marketplace trends, plan design changes, compliance-related fees, and other relevant factors that impact the cost of claims to be paid by the Company (Exhs. DPU-8-5; AG-13-17; AG-13-17, Atts. 1-2).

to control its medical and dental expenses (Company Brief at 104). In particular, the Company describes cost containment steps such as self-insuring its health and welfare plans, obtaining a volume discount for its new prescription drug plan, periodically soliciting bids for alternative health care providers, and moving benefits administration to a new, third party to provide better service at lower costs (Company Brief at 104).

National Grid also argues that its proposed adjustment to test year health costs conforms to Department requirements (Company Brief at 107). The Company explains that its rate year level of medical and dental expense is based on the test year-end actual employee plan elections and associated individual plan cost rates that are in effect for calendar year 2016 (Company Brief at 108, citing Exhs. NG-MPG-1, at 26; AG-13-17). Further, National Grid explains that the individual plan cost rates, developed by its external benefits consultant, Towers Watson, are derived on the basis of current and historical information pertaining to National Grid's employee base, including past claims experience, administrative fees and other elements (Company Brief at 108, citing Exh. AG-13-17). The Company argues that the Department should rely on the working rates because they are developed using actuarial principles similar to the analysis formerly used to generate insurance premiums, which the Department accepts as the basis for post-test year changes in health care insurance costs (Company Brief at 109). The Company also contends that its decision to self-insure and use working rates that do not include additional costs present in insurance premiums produces substantial benefits for customers in the form of reduced benefit costs (Company Brief at 109). Finally, the Company claims that the Department has expressly recognized that the use of working rates to identify the representative level of costs on a post-test year basis is a reasonable method for the rate-setting process (Company Brief at 110, citing D.P.U. 92-210, at 43-44; D.P.U. 95-40, at 22). Thus, the Company asserts that the Department should rely on the working rates (Company Brief at 108).

3. Analysis and Findings

To be included in rates, medical and dental insurance expenses must be reasonable. D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (1991). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. Berkshire Gas Company, D.T.E. 01-56, at 60 (2002); 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 medical and dental insurance expenses are reasonable and that the Company has taken reasonable and effective measures to contain health care costs (Exhs. NG-MPH-1, at 22-25; NG-MPH-3, at 23-30; NG-MPH-10, at 24-31; DPU-8-11; DPU-8-13; DPU-8-14). For example, the Company disaggregated its prescription drug programs from each medical plan and replaced them entirely with a CVS Caremark plan, providing volume discounts (Exh. NG-MPH-1, at 24). Additionally, National Grid introduced generic step therapy to the CVS Caremark plan in order to lower prescription drug costs (Exh. NG-MPH-1, at 24). The Company also held a competitive bidding process for alternative health care providers in 2015 that produced a five percent reduction in administrative fees beginning in 2016 across all populations administered by Blue Cross Blue Shield of Massachusetts, the Company's current national medical vendor (Exh. DPU-8-14).

Turning to National Grid's proposed post-test year decrease in medical and dental expense, the Company maintains that the working rates provided by Towers Watson 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 108-109). The Department has previously 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. 14-150, at 151; D.P.U. 13-90, at 94. In the current case, however, National Grid's working rates are derived using almost exclusively Company-specific data such as medical and prescription drug claims experience, enrollment figures, plan design details, administration costs, and fees (Exhs. DPU-13-10, Att.; DPU-28-1, Att.; DPU-28-2; DPU-28-3; Tr. 4, at 551-553; RR-AG-4; RR-AG-9; RR-AG-11). The Company's working rates rely in part on industry-wide "trend rates" and "margins" (Tr. 4, at 551-553; RR-DPU-20). The "trend rate" represents the expected annual increase in the average cost of medical services ("medical inflation") and is derived using historical gross cost experience from 467 employers including National Grid, other employers in the energy services sector, and general industry employers (Exh. DPU-28-2; RR-DPU-20). The "trend rate" is used to adjust National Grid's 2014 medical and prescription drug claims to 2016 dollars (Tr. 4, at 534-535; RR-AG-5). The "margin" is a load applied to the final working rates to account for fluctuations in claims and is derived by comparing National Grid's own claims experience to the market (Exh. DPU-28-2, at 2; Tr. 4, at 542 and 552). The "trend rate" and "margin" components both include Company data and would be included in rate year insurance cost calculations regardless of whether the Company chose to self-insure or rely on third-party insurance carriers (Tr. 4, at 542). Based on the foregoing analysis, the Department finds that National Grid's working rates are sufficiently correlated with the Company's own experience (i.e., versus that of a broad based pool of insured entities) to warrant their use in determining the Company's health care expense in this proceeding.

Additionally, National Grid's decision to self-insure its medical and dental plans results in direct savings to ratepayers in the form of lower employee benefit costs (Tr. 4, at 523-524 and 542-543). The Department recognizes that disallowing National Grid's post-test year adjustments on the basis of working rates would provide a disincentive for companies to implement aggressive cost control measures, such as switching to self-insurance, when such measures otherwise would be deemed cost-effective. D.P.U. 95-40, at 26; D.P.U. 92-210, at 22. Therefore, the Department accepts the Company's proposed decrease to medical and dental expense of $263,968 (Exh. NG-RRP-2, at 11 (Rev. 3)).

In addition to National Grid's proposed medical and dental expense adjustment, the Department removes post-test year medical and dental expenses of $86,778 associated with 37 vacancies previously excluded from the Company's proposed cost of service in Section VIII.A.4.c.[130] Accordingly, the Department reduces the Company's proposed cost of service by $86,778.

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130 ($63,043 medical and dental costs for proposed Company vacancies * .5234 O&M percentage of base wages = $32,994) + ($415,448 medical and dental costs for proposed NGSC vacancies * .1920 percentage of NGSC salary expenses allocated to Company payroll expense * .6744 O&M percentage of base wages = $53,783) = $86,778 reduction to proposed Company medical and dental expense adjustment (see Exh. NG-RRP-2, at 11 (Rev. 3)).

D. Uncollectible Expense

1. Introduction

During the test year, National Grid booked $62,292,694 in bad debt expense (uncollectible expense) related to its total operations (Exh. NG-RRP-2, at 4, 5, 19 (Rev. 3)). The Company proposes to decrease its total bad debt expense by $44,676,591 over the test year level based on the application of a bad debt ratio of 1.23 percent to delivery service revenues to arrive at delivery-related bad expense of $17,616,103 (Exhs. NG-RRP-1, at 23; NG-RRP-2, at 19 (Rev. 3)).[131]

The Company calculated its delivery service related bad debt ratio by dividing its total delivery service net write-offs for the twelve-month periods ending on June 30, 2013, June 30, 2014, and June 30, 2015 of $46,996,526 by its total delivery service retail revenues for that same three-year period of $3,826,016,551 (Exh. NG-RRP-2, at 19 (Rev. 3)). This calculation results in a bad debt ratio of 1.23 percent (Exh. NG-RRP-2, at 19 (Rev. 3)). The Company then multiplied the bad debt ratio of 1.23 percent by test year normalized delivery service revenues of $1,434,137,931,[132] to arrive at a bad debt expense of $17,616,103 (Exh. NG-RRP-2, at 19 (Rev. 3)).[133] The resulting bad debt expense of $17,616,103 represents a decrease of

131 The supply-related portion of the bad debt expense is recovered through basic service rates. Therefore, the bad debt ratio is applied to only the delivery service revenues.

132 In the calculation of delivery service revenues in its initial filing, the Company did not include the adjustments for the low-income discount (a $61,180,895 credit) and the net metering lost distribution revenues (a $23,760,587 credit) (RR-DPU-49 & Att.).

133 Any discrepancies in amounts are the result of rounding the bad debt ratio, which the Company computes using a floating decimal of 1.2283409 (see Exh. NG-RRP-2, at 19 (Rev. 3)).

$44,676,591 when compared to the Company's test year level of expense of $62,292,694 (Exh. NG-RRP-2, at 19 (Rev. 3)).

The Company also calculated a bad debt expense associated with the proposed revenue increase. The Company multiplied the bad debt ratio of 1.23 percent by its proposed revenue increase of $201,900,249, to arrive at a proposed bad debt adjustment of $2,480,023 (Exh. NG-RRP-2, at 2, 19 (Rev. 3)).

2. Positions of the Parties

The Company asserts that it has properly calculated its uncollectible expense adjustment consistent with the Department precedent (Company Brief at 54-55, citing D.P.U. 14-150, at 158; D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71). No other party addressed the Company's bad debt calculations on brief.

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt in their cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; Commonwealth Electric Company/Cambridge Electric Light Company, D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140 (1991). The Department has found that the use of the most recent three years of data available is appropriate in the calculation of bad debt expense. D.P.U. 96-50 (Phase I) at 71. A company's bad debt ratio is derived by dividing the three-year delivery service net writ-offs by the delivery service billed revenues for the same period. Western Massachusetts Electric Company, D.P.U. 84-25, at 113-114 (1984); D.P.U. 1720, at 27; Massachusetts-American Water Company, D.P.U. 1700, at 22 (1984). This bad debt ratio is then multiplied by test year delivery service billed revenues, adjusted for any distribution revenues increase or decrease that is approved in the current rate case. See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71.

The Department has reviewed the Company's bad debt calculations, the materials supporting the calculations, and other related record evidence (Exhs. NG-RRP-1, at 23; NG-RRP-2, at 2, 4, 5, 19 (Rev. 3); WP-NG-RRP-12; AG-DJE-1, at 7-10 & Sch. DJE-2; NG-RRP-Rebuttal-1, at 37-39; AG-DJE-Rebuttal-1, at 3; DPU-12-8; DPU-12-9; DPU-12-10; AG-2-30; AG-14-8; Tr. 14, at 1574-1576; RR-DPU-49). The Department concludes that the method used by the Company to calculate its uncollectible expense adjustments is consistent with the Department precedent. D.P.U. 09-39, at 164; D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140. Therefore, the Department approves the application of the Company's delivery service related bad debt ratio of 1.23 percent, applied to test year delivery service revenues (Exh. NG-RRP-2, at 2, 19 (Rev. 3)).

As set forth above, application of the 1.23 percent bad debt ratio to the test year normalized delivery service revenues of $1,434,137,931, produces a bad debt expense of $17,616,103 (Exh. NG-RRP-2, at 19 (Rev. 3)). During the test year, the Company booked $62,292,694 in bad debt expense related to its total operations (Exh. NG-RRP-2, at 4, 5, 19 (Rev. 3)). Accordingly, the Department approves the Company's proposed decrease to its test year cost of service in the amount of $44,676,591.

Further, as set forth above, the Company calculated a bad debt expense of $2,480,023 associated with its proposed revenue increase (Exh. NG-RRP-2, at 2, 19 (Rev. 3)). Applying the same 1.23 percent bad debt ratio set forth above to the distribution revenue increase approved in this case of $169,670,239 results in a bad debt expense in the amount of $2,084,129. Accordingly, the Department reduces the Company's proposed cost of service by $395,894.

E. Depreciation Expense

1. Introduction

During the test year, National Grid booked $123,025,248 in depreciation expense (Exh. NG-RRP-2, at 27 (Rev. 3)).[134] The Company proposes to increase its depreciation expense by $3,650,455 to $126,675,703, based on a "technical update" of the depreciation study provided in the Company's previous rate case, D.P.U. 09-39 ("2009 Depreciation Study") (Exhs. NG-RRP-2, at 27 (Rev. 3); NG-REW-1, at 3; NG-REW-2). The technical update results in a reduction in the Company's current composite depreciation accrual rate from 3.19 percent to 3.18 percent (Exh. NG-REW-2, at 36).

The Company's depreciation accrual rates include a provision for salvage (Exhs. NG-REW-1, at 7; NG-REW-2, at 5). When National Grid retires plant, the associated scrap materials are initially returned to crew barns, where they are then transferred to 40-foot containers (Tr. 2, at 212-213). These containers are periodically shipped to National Grid's investment recovery operation in Syracuse, New York, where the materials are processed and sold at auction, with the proceeds credited to standing retirement work in progress blanket work

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134 This amount excludes $2,527,499 in depreciation expense associated with Nantucket Electric's submarine cables and $1,671,463 in depreciation expense associated with SmartGrid (Exh. NG-RRP-2, at 27 (Rev 3)). The Company excluded this depreciation expense because the cost of the Nantucket submarine cables and these SmartGrid expenses are recovered through separate mechanisms (Exhs. DPU-31-6; DPU-31-7).

orders[135] (Exh. AG-18-9; Tr. 2, at 213). In March of 2015, National Grid transferred to their respective plant accounts $26,225,351 in salvage that had been accumulated in MECo's blanket work orders between 2007 and March 2015 to their respective plant accounts (Exhs. AG-18-9; AG-30-1, Att.).

2. Company's Depreciation Technical Update

The Company did not perform a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past (Exh. NG-REW-1, at 3). Instead, the Company performed a technical update ("2015 Technical Update") of the 2009 Depreciation Study (Exhs. NG-REW-1, at 3; NG-REW-2). A technical update generally retains the parameters developed and/or approved in the most recent full depreciation study, and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates that have occurred over the passage of time (Exh. NG-REW-1, at 3). A technical update, therefore, is intended to align a company's depreciation rates with the accounting year during which the rates will become effective (Exh. NG-REW-1, at 3).

The 2009 Depreciation Study was based on plant data as of the end of the test year used in D.P.U. 09-39 (i.e., December 31, 2008), and employed the remaining life method (Exh. AG-3-40, at 19). Under the remaining life method, the net un-depreciated plant investment, net of salvage, is assigned through equal annual depreciation charges over the

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135 Because of the limited amount of scrap materials generated by Nantucket Electric and prohibitive transport costs associated with ferrying containers off the island, scrap sales associated with Nantucket Electric are minimal (Exh. NG-DJD-Rebuttal-1, at 13; Tr. 2, at 220).

remaining estimated life of the property (Exh. AG-3-40, at 19). For most of its plant accounts, the Company uses the retirement rate method[136] to develop an average service life ("ASL") for each account by plotting life table data that were then fitted to Iowa-type survivor curves[137] to determine the appropriate survivor curve for these accounts[138] (Exh. NG-REW-1, at 6-7).

The steps involved in preparing a technical update generally include: (a) data collection; (b) calculation of service life statistics; (c) computation of average net salvage rates; (d) rebalancing of depreciation reserves; and (e) development of accrual rates (Exh. NG-REW-1, at 5). The Company explains that data was collected and applied by documenting plant accounting and depreciation reserve transactions from 2009 through 2014, and age distributions of surviving plant until December 31, 2014, which the Company's depreciation consultants then added to its 2009 Depreciation Study data (Exh. NG-REW-1, at 3). The Company matched accounting entries with transaction codes to identify and distinguish various types of plant accounting transactions (Exh. NG-REW-1, at 3-4).

The Company states that with the exception of certain general plant categories for which amortization accounting previously has been approved, the depreciation rates developed in the

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136 The retirement rate method is an actuarial method of deriving survivor curves based on the average rates at which property of each age group is retired by the Company over the period of time included in the depreciation study (Exh. NG-6, at 77).

137 Iowa curves are frequency distribution curves that were initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; these curves are widely accepted in determining average life frequencies for utility plant. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). Initially, 18 curve types were published in 1935; four additional survivor curves were identified in 1957. D.P.U. 09-39, at 168 n.106.

138 The ASL and Iowa curve are customarily reported as a combined figure; for example, a "75-R2.5" curve refers to an ASL of 75 years combined with an R2.5 Iowa curve.

2015 Technical Update were calculated using the straight line method, vintage group procedure, and remaining life techniques (Exh. NG-REW-1 at 7). The Company then developed composite life statistics for each required account (Exh. NG-REW-1, at 7).

3. Attorney General's Depreciation Analysis

The Attorney General challenges the underlying premises of the Company's proposed depreciation accrual rates. According to the Attorney General, National Grid's 2015 Technical Update was limited to updating various balances and salvage data, and that its failure to update projection curves, projection lives, future cost of removal and gross salvage rates resulted in accrual rates that are virtually identical to the Company's existing rates (Exh. AG-WDA-1, at 8-10).

The Attorney General identifies other deficiencies indicated by the 2015 Technical Update. First, the Attorney General contends that while the 2015 Technical Update indicates that National Grid's theoretical depreciation reserve[139] should be $1,492,421,587, the Company's salvage practices have resulted in a recorded depreciation reserve of $1,655,620,338, indicating a depreciation reserve surplus of $163,198,751 as of December 31, 2014[140] that continues to grow (Exhs. AG-WDA-1, at 8, 10, 13-15).

The Attorney General states that this surplus situation has been further exacerbated by the Company's failure to properly treat salvage (Exh. AG-WDA-1, at 10-15). The Attorney General

139 The theoretical depreciation reserve represents the amount that should be in the depreciation reserve if the depreciation accrual rates presently in effect were to remain in use until all of that company's plant in service as of that date of the reserve calculation has been retired (Exh. AG-WDA-5, at 3; Tr. 13, at 1509).

140 The Attorney General adds that because of the Company's failure to properly record salvage, the depreciation reserve surplus was actually $189,048,306 as of that date (Exh. AG-WDA-1, at 10).

explains that while the USOA-Electric Companies requires that salvage be credited to the depreciation reserve, the Company accumulated salvage in blanket work orders for a number of years, and only credited the salvage on March 15, 2015, after the completion of the 2015 Technical Update (Exh. AG-WDA-1, at 4-7). The Attorney General states that if the Company had adhered to the salvage recording requirements of the USOA-Electric Companies, an additional $25,849,645 relating to salvage for the years 2007 through 2014 would have been credited to National Grid's depreciation reserve as of December 31, 2014 (Exh. AG-WDA-1, at 5-8).[141]

Further, the Attorney General notes that according to the National Association of Regulatory Utility Commissioners' Public Utility Depreciation Practices Manual (August 1996) ("NARUC Manual"), a utility should take immediate action to reduce depreciation imbalances, such as the implementation of revised depreciation accrual rates (Exh. AG-WDA-1, at 12, 16-18), Despite this obligation, however, the Attorney General estimates that under the Company's proposed accrual rates, it would take over 500 years to pass this surplus back to customers (Exh. AG-WDA-1, at 10-11),

Next, the Attorney General contests National Grid's proposed accrual rates. Specifically, the Attorney General notes that National Grid's proposed ASLs are, on average, shorter than the Department-approved ASLs currently in use by Western Massachusetts Electric Company ("WMECo") and NSTAR Electric Company ("NSTAR Electric") for most of the larger plant

141 In her initial testimony, the Attorney General added the $25,849,645 surplus back to the Company's depreciation reserve to develop her proposed accrual rates (Exh. WDA-1, at 8; AG-WDA-3). On rebuttal testimony, the Attorney General determined that, given the complexities and relatively small dollar effects, no such adjustment was necessary, and thus revised her accrual rates accordingly (Exhs. AG-WDA-Rebuttal-1, at 4-5; AG-WDA-Rebuttal-2).

accounts (Exhs. AG-WDA-1, at 21; AG-WDA-4). The Attorney General performed an actuarial analysis for each Company plant account developing ASLs, Iowa curves, and salvage factors using the formulas and requirements for an actuarial analysis that are set forth in the NARUC Manual (Exhs. AG-WDA-34, at 9; AG-WDA-1, at 20-21; AG-WDA-4). Based on her analysis, the Attorney General calculated different accrual rates for 26 of the Company's 31 transmission, distribution, and depreciable general plant accounts (Exhs. AG-WDA-3, at 5, 9; AG-WDA-Rebuttal-2; AG-WDA-Rebuttal-3). These accrual rates produce a composite accrual rate of 2.77 percent versus the Company's proposed composite accrual rate of 3.18 percent (Exhs. AG-WDA-Rebuttal-1, at 4-5; AG-WDA-Rebuttal-2, at 2).

4. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General offers a number of recommendations concerning the Company's depreciation rates and practices (Attorney General Brief at 63-64). First, the Attorney General recommends that the Department require the Company to record salvage within 18 months of the retirement of its assets (Attorney General Brief at 63). Second, the Attorney General recommends that the Department adopt her depreciation accrual rates and reject the Company's 2015 Technical Update (Attorney General Brief at 63, citing Exhs. AG-WDA-1; AG-WDA-2; AG-WDA-3; AG-WDA-4; AG-WDA-Rebuttal-1; AG-WDA-Rebuttal-2). Finally, the Attorney General recommends that the Company's depreciation rates should be recalculated to account for retired plant that she contends had not been removed from National Grid's gross plant accounts (Attorney General Brief at 63-64).

ii. Salvage Accounting

The Attorney General argues that National Grid misrepresents its net rate base, that the Company has been doing so for several years, and has been commensurately over charging ratepayers (Attorney General Brief at 64). The Attorney General contends that from 2007 through 2014, National Grid failed to record $25,849,645 of salvage to its plant accounts at the time plant was retired, and instead allowed this balance to accumulate in retirement work in progress blanket work orders that had been kept open (Attorney General Brief at 65, citing Exhs. AG-18-9, AG-30-9). Further, the Attorney General claims that National Grid did not credit the accumulated salvage for those years to the depreciation reserve until March 31, 2015, as opposed to crediting salvage to the depreciation reserve when the assets were retired (Attorney General Brief at 65, citing Exh. NG-DJD-Rebuttal-1, at 4). In addition, she asserts that National Grid's failure to record salvage cannot be reasonably attributed to National Grid's SAP implementation issues because the Company had stopped recording salvage several years before the inception of the SAP project on November 5, 2012 (Attorney General Brief at 65-66, citing Exh. NG-MLK-1, at 29).

The Attorney General argues that National Grid's failure to properly record salvage violated the Department's accounting requirements (Attorney General Brief at 64-65; Attorney General Reply Brief at 46-47). More specifically, she contends that the Department requires electric distribution companies to maintain their books in accordance with the USOA-Electric Companies (Attorney General Brief at 65). According to the Attorney General, the USOA-Electric Companies requires that at the time depreciable utility plant is retired, the account shall be charged with both the book cost of the property being retired and the cost of removal, and shall be credited with the salvage value and any other amounts recovered, such as insurance proceeds (Attorney General Brief at 65, citing 18 CFR Part 101, Account 108(B)).[142] Instead, the Attorney General alleges that the Company accumulated $25,849,645 of salvage in retirement work in progress blanket work orders from 2007 through 2014 that it kept open during this period (Attorney General Brief at 65, citing Exhs. NG-DJD-Rebuttal-1, at 4; AG-18-9; AG-30-9).

The Attorney General argues that the Company's violations of salvage accounting requirements had the effects of both inflating the Company's rate base and making it "impossible" to properly evaluate the Company's salvage rates used to derive its depreciation accrual rates (Attorney General Brief at 66, 69-70). According to the Attorney General, the Company's failure to record salvage in 2007 and 2008 attributable to MECo resulted in a rate base that was overstated by $4,992,994 (Attorney General Brief at 66, citing Exh. AG-30-1, Att. at 1). The Attorney General calculates that, based on the 7.85 percent overall rate of return granted to National Grid in D.P.U. 09-39, the Company has collected $391,950 in excessive returns during each of the years that the rates set by D.P.U. 09-39 have been in effect, thus producing an over-collection of over $2 million over the past six years (Attorney General Brief at 66-67). Moreover, the Attorney General points out that, because these dollars were included in base rates, the Department is "powerless" to return the money to customers due to the prohibition on retroactive ratemaking (Attorney General Brief at 67, citing Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. 625,

[142] The Attorney General points out that there is nothing in 220 C.M.R. § 51.02 or § 51.03 that modifies the USOA-Electric Companies' requirements regarding the recording of salvage (Attorney General Brief at 65).

637–38 (2004), citing Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 6 (1978)).

Further, the Attorney General argues that the Company's failure to properly record salvage has resulted in excessive charges being recovered through the CapEx mechanism (Attorney General Brief at 67).[143] Specifically, the Attorney General alleges that because the Company continued to withhold tens of millions of dollars in salvage since 2008 (the Company's test year in D.P.U. 09-39), this failure to properly record salvage would have caused the Company to overcharge customers in each and every year up to and including the 2014 reconciliation year in its CapEx dockets (Attorney General Brief at 67, citing Exh. AG-30-1, Att. 1).[144] However, the Attorney General asserts that because the CapEx is a reconciling mechanism, the Department can order retroactive adjustments and return these excess collections to ratepayers with interest (Attorney General Brief at 67, citing Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. at 637–38 (holding that the rule against retroactive ratemaking does not apply to rate mechanisms outside of base rates); Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 28 (2001)). Consequently, the Attorney General recommends that the Department open a proceeding to return the over-collection with interest to ratepayers (Attorney General Brief at 67).[145]

143 As discussed in Section V above, the Company's CapEx mechanism is now known as the CIRM.

144 The Attorney General identifies the following CapEx dockets: D.P.U. 10-79 (2009); D.P.U. 11-60 (2010); D.P.U. 12-48 (2011); D.P.U. 13-84 (2012); D.P.U. 14-95 (2013); and D.P.U. 15-82 (2014) (Attorney General Brief at 67).

145 The Attorney General provides that in the alternative, if the Department elects to keep the Company's capital tracker, the Department could direct the Company to refund

Additionally, the Attorney General recommends that the Department direct National Grid, on a to going forward basis, to credit salvage amounts to the accumulated provision for depreciation as required by the USOA-Electric Companies, and record such salvage amounts to the data file that would be used in a depreciation study within 18 months of National Grid's selling any Company asset or otherwise accruing salvage (Attorney General Brief at 68-69).

Finally, the Attorney General recommends that the Department set National Grid's allowed return on common equity at the lowest end of the range of reasonability, as a result of the Company's alleged systematic failure to maintain its salvage records in accordance with Department requirements (Attorney General Brief at 67-68; Attorney General Reply Brief at 47). The Attorney General considers this reduction to be reasonable and appropriate, and asserts that it will prevent National Grid and other companies from engaging in practices that result in the misrepresentation of their rate base in the future (Attorney General Brief at 69).

iii. Depreciation Analysis

The Attorney General notes that National Grid relies on the same life-curves as those approved in D.P.U. 09-39 (Attorney General Brief at 70; Attorney General Reply Brief at 36). The Attorney General maintains that as a result of the Company's use of these life-curves, National Grid has proposed to use in most cases shorter depreciation lives that are appropriate (Attorney General Brief at 70; Attorney General Reply Brief at 36). The Attorney General asserts that the Department should lengthen the Company's proposed depreciation lives for a number of reasons.

customers as part of its next capital investment report filing (Attorney General Brief at 67 n.26).

First, the Attorney General argues that the use of life curves will assist in remedying what she considers to be excess depreciation reserves. According to the Attorney General, the Company has a relatively large $163 million reserve surplus, a disparity that she maintains is growing and warrants immediate adjustment (Attorney General Brief at 70; Attorney General Reply Brief at 36, 40, citing Exh. NG-6, at 189). The Attorney General rejects the notion that when delayed retirements are included, the Company's pro forma excess reserve balance was only $77 million at the end of 2015 (Attorney General Reply Brief at 40-41). According to the Attorney General, the Company's reserve calculations fail to credit approximately $130 million in depreciation expense booked to both MECo's and Nantucket Electric's reserves for 2015 (Attorney General Reply Brief at 41, citing Exhs. NG-DJD-Rebuttal-2; AG-5; Tr. 2, at 202; Tr. 13, at 1486–1487). Thus, the Attorney General contends that had National Grid conducted its own analysis properly, factoring delayed retirements into the calculation actually suggests that the Company's depreciation reserve would have been $200 million, which is even higher than the surplus reported in its 2015 Technical Update (Attorney General Reply Brief at 41).

Second, the Attorney General argues that her proposed life curves fit the data better than those that the Company proposes to continue using (Attorney General Brief at 71). In this regard, the Attorney General contends that the Company's SAP implementation issues had no effect on her analysis of post-2008 data, because (1) the Company did not begin the SAP implementation process until late in 2012, and (2) her own sensitivity analyses demonstrates that, even if all of the data from the SAP implementation period were excluded, her recommended life curves still fit the data better than the Company's current life curves for all but one account (Attorney General Reply Brief at 37-38).

Third, the Attorney General points out that the Company's current ASLs are comparably shorter than those in effect for NSTAR Electric and WMECo (Attorney General Brief at 71; Attorney General Reply Brief at 36). The Attorney General argues that National Grid has failed to offer any evidence that a comparison of the Company to either NSTAR Electric or WMECo is inappropriate (Attorney General Reply Brief at 42).[146]

Finally, the Attorney General contends her depreciation witness is highly familiar with electric utility facilities, and was able to obtain all necessary information through the discovery process in order to analyze the Company's ASLs (Attorney General Reply Brief at 39-40). In this regard, she asserts that the Company's criticism that her witness failed to conduct a site visit of National Grid's facilities is without merit (Attorney General Reply Brief at 39).

Based on her analysis, the Attorney General proposes increased ASLs and different net salvage amounts for the Company's transmission and distribution plant accounts (Attorney General Brief at 71; Attorney General Reply Brief at 36). The Attorney General calculates that her recommended accrual rates produce a reduction of $15,937,950 in the Company's proposed annual depreciation expense (Attorney General Brief at 70, citing Exhs. AG-WDA-3-Rebuttal, at 2; NG-RRP-2, at 27.).

iv. Delayed Retirement

The Attorney General recommends that the Department adjust the Company's proposed depreciation expense for delayed retirements that are included in the Company's plant in service (Attorney General Brief at 82). According to the Attorney General, the Company concedes that

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146 By way of example, the Attorney General contends that there is no record evidence suggesting that National Grid's underground conduit can be expected to have a shorter life than underground conduit installed in the service territories of other Massachusetts electric distribution companies (Attorney General Reply Brief at 39).

it overstates its gross plant in service for the test year by amounts that actually should have been booked as retirements (Attorney General Brief at 82, citing Tr. 2, at 228; RR-AG-28). The Attorney General claims that the Company's delinquency in reporting delayed retirements in the year in which they occurred is specifically prohibited by FERC and Department regulations (Attorney General Reply Brief at 45-46).[147] The Attorney General recommends that the Department set the Company's ROE at the lowest end of the range of reasonableness for its purported misrepresentation of gross and net plant resulting from delayed retirements (Attorney General Reply Brief at 46-47).

Further, the Attorney General recognizes that when National Grid retires plant booked to Account 101, it appropriately makes a corresponding adjustment to the accumulated depreciation reserve in Account 108, thus producing a rate base-neutral outcome (Attorney General Reply Brief at 43 n.14). Despite this rate base neutrality, however, the Attorney General points out that because depreciation expense is calculated based on gross plant in service and not net rate base, debits entries to Account 108 do not make the delayed retirements revenue neutral in terms of depreciation expense (Attorney General Reply Brief at 43). The Attorney General notes that while National Grid is correct in that delayed retirements should not trigger a rate base adjustment, the Company does not dispute that a commensurate accounting of depreciation expense is required (Attorney General Reply Brief at 43, citing Company Brief at 160).

In her initial brief, the Attorney General proposed to calculate the depreciation expense adjustment by multiplying her recommended composite depreciation accrual rate of 2.77 percent

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[147] The Company defines asset unitization as the process by which the charges accumulated in the completed construction not classified account at a gross level are classified by accounts and retirement units (Exh. NG-DJD-Rebuttal-1, at 10).

by $107,400,000 in gross plant, producing an adjustment of $2,974,980 (Attorney General Brief at 84-85). On her reply brief, the Attorney General accepted the Company's proposal to calculate the adjustment by multiplying a composite depreciation accrual rate by $52,697,141 in plant that actually had been physically retired prior to the end of the test year, but remained recorded on the books after June 30, 2015 (Attorney General Reply Brief at 43). Based on her proposed depreciation accrual rates, the Attorney General calculates an adjustment of $1,459,711 under this approach[148] (Attorney General Reply Brief at 43).

b. Company

i. Introduction

National Grid defends its decision to confine its depreciation analysis in this proceeding to its 2015 Technical Update (Company Reply Brief at 55-56). According to National Grid, the SAP stabilization process occurred from November 2012 to September 2014 (Company Reply Brief at 56). The Company argues that the stabilization process resulted in what it considered to be "unavoidable" disruptions in the processing of plant transactions and that these disruptions could have affected retirement and net salvage data recorded during this period, and, therefore, would have adversely affected the Company's ability to estimate projection curves, projection lives, and future net salvage rates (Company Reply Brief at 56, citing Exhs. NG-MLR-1, at 26-29; AG-3-1). Thus, the Company asserts that under these conditions, a full depreciation study using plant data documented before the SAP stabilization would have taken considerable time and effort to conduct, and had the potential to produce results that were unreliable and inconsistent with reasonable utility practice (Company Reply Brief at 56, citing Exh. AG-3-1,

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148 $52,697,141 * 2.77 percent = $1,459,711.

at 2). As such, the Company concludes that although under normal circumstances a full depreciation study would have been warranted, in this case, a technical update could support the analysis required for calculating depreciation expense, with the 2009 Depreciation Study being used for limited support (Company Reply Brief at 56).

ii. Salvage Accounting

National Grid argues that the Attorney General's recommendations concerning the crediting of salvage to accumulated depreciation are unnecessary (Company Brief at 157). According to the Company, after it first experienced SAP implementation issues, National Grid encountered delays in processing plant transactions, such as asset unitization and retirements (Company Brief at 157-158, citing Exhs. NG-DJD-Rebuttal-1, at 5; AG-29-4). The Company argues that even after the SAP system was stabilized, there was a backlog of transactions to be processed that caused a delay in recording salvage, as well as the need to resolve conversion, data, and mapping errors that had occurred (Company Brief at 157-158, citing Exh. NG-DJD-Rebuttal-1, at 6). The Company contends that had the retirements and associated cost of removal pertaining to work orders placed in service prior to December 31, 2014 been accounted for in the proper period, rather than through a retrospective correction, the pro-forma excess reserve would be approximately $77 million, an imbalance that National Grid represents as being within the ten-percent deviation that is acceptable in the utility industry (Company Brief at 159, citing Exh. NG-DJD-Rebuttal-1, at 12; Tr. 2, at 239).

Moreover, the Company attributes delays in unitizing the salvage proceeds associated with blanket work orders to the logistical challenge associated with classifying physical containers full of scrap materials generated from capital work orders for identification and disaggregation into their respective FERC accounts (Company Brief at 156, citing Exh. NG-DJD-Rebuttal-1, at 10-11). National Grid maintains that it currently is not experiencing any undue delays in recording salvage due to SAP implementation issues, and considers there to be no need for an “arbitrary” 18-month requirement, particularly for situations where reasonable delays can occur in recording all transactions associated with asset retirements (Company Brief at 158).

Additionally, the Company denies the Attorney General’s assertion that net rate base in any year 2007 through 2015 was overstated for ratemaking purposes (Company Brief at 155-156, citing Exh. AG-WDA-Rebuttal-1, at 4).[149] The Company contends that the delays cited by the Attorney General were primarily due to the delays in processing salvage material as noted above, and that such delays did not purposefully distort its net rate base or erroneously postpone booking salvage for the period of 2007 through 2014 (Company Brief at 155). As such, the Company argues that the Attorney General’s assertions on this point should be disregarded (Company Brief at 156).

The Company also contends that the Attorney General’s assertions regarding over-collection through the CapEx are groundless, because total plant additions and cost of removal surpassed the $170 million cap each year from 2009 through 2015 (Company Brief at 155, citing RR-DPU-13). The Company asserts that the annual accumulations totaling $25,849,645 of salvage would not have altered recovery under the CapEx in any one year (Company Brief at 155, citing RR-DPU-13). Thus, the Company rejects any notion that it

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149 National Grid asserts that the Attorney General’s depreciation witness made no further mention of the Attorney General’s allegations of an overstated rate base once the Company demonstrated that the witness’s proposed adjustment was actually one-sided (Company Brief at 155-156).

“overstated" its net rate base in both D.P.U. 09-39 and its annual CapEx filings, and over-collected more than $2 million during the period in question through base rates and the CapEx (Company Brief at 155-157). For these reasons, National Grid argues that the Attorney General’s recommendation to decrease the Company’s ROE is baseless (Company Brief at 155).

iii. Depreciation Analysis

National Grid submits that it is not proposing to change the ASLs and survivor curves approved in its last rate case, D.P.U. 09-39 (Company Brief at 152, citing Exhs. NG-REW-1, at 4; NG-REW-2, at 17-18; AG-3-1). The Company asserts that its survivor curves were estimated in the 2009 Depreciation Study from a statistical analysis of past retirement experience along with forecasting for future changes (Company Brief at 152, citing Exh. NG-REW-1, at 4-5). The Company notes that beginning with its 2009 Depreciation Study, it next recorded statistics for each vintage in its technical update to account for known and measurable changes in the age distributions of surviving plant from December 31, 2008 through December 31, 2014 (Company Brief at 152, citing Exh. NG-REW-1, at 5).

The Company questions the Attorney General’s proposed longer survivor curves, and denies the assertion that the Attorney General’s curves have a statistically superior fit and that the reserve balance is increasing (Company Brief at 158, citing Attorney General Brief at 70-71). Rather, National Grid argues that the Attorney General’s proposed ASL curves are faulty because they are based on inadequate historical data from 2009 and 2014, which was the result of the Company’s SAP implementation issues (Company Brief at 158, citing Exh. AG 3-1).

iv. Delayed Retirement

The Company disputes the level of the Attorney General's proposed depreciation expense calculation (Company Brief at 160-161). National Grid contends that when it retires plant booked to Account 101, it appropriately makes a corresponding adjustment to the accumulated depreciation reserve in Account 108, which produces a rate base-neutral outcome and obviates the need for any rate base adjustment (Company Brief at 160). Moreover, the Company contends that the Attorney General's claimed $107,400,000 in retired plant actually includes $56,682,851 in plant that had been retired prior to December 31, 2014, but recorded on the Company's books prior to the end of the test year, and thus not recorded in the test year-end balance of gross plant (Company Brief at 161, citing RR-AG-28). Based on its determination that $52,697,141 in retirements was still on the Company's books as of the end of the test year, the Company considers that a depreciation expense adjustment of $1,675,769 would be warranted (Company Brief at 161).

5. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. 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); Boston Edison Company, D.P.U. 1350, at 97 (1983). 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.[150] 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 I) at 54-55. To the extent a depreciation study provides a

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150 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.

clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

b. Salvage Accounting

The USOA-Electric Companies specifies that salvage shall be charged or credited, as appropriate, to the depreciation reserve. 18 CFR Part 101, Electric Plant Instructions, § 10(B)(2), Account 108; 220 C.M.R. § 51.01. There is no specific time limit beyond a requirement that proper distributions be made upon the completion of a work order. 18 CFR Part 101, Electric Plant Instructions, § 10(B)(2), Account 108; 220 C.M.R. § 51.01.

While National Grid objects to the Attorney General's proposal that salvage be credited within 18 months, the Company recently has instituted measures intended to improve its recording of salvage. Until recently, it was not possible for the Company's investment recovery staff to develop engineering estimates that would allow scrap material to be unitized by FERC plant account (Tr. 2, at 215). The Company has now implemented a process wherein the plant accounting department and investment recovery staff will collaborate to generate engineering estimates to support the unitization of scrap metal proceeds associated with standing blanket work orders (Exh. NG-DJD-Rebuttal-1, at 13; Tr. 2, at 215, 234). The Company represents that this procedure will provide sufficient salvage data to conduct depreciation study analysis at least annually (Exh. NG-DJD-Rebuttal-1, at 13). The Department expects that National Grid's new unitization procedure will allow the Company to complete the salvage recording process well within the 18 months proposed by the Attorney General. We are aware that there may be situations where salvage may remain in a blanket work order for a longer period of time, but we expect that those situations will be relatively rare. Based on the foregoing analysis, the

Department finds that 18 months represents a reasonable period for National Grid to complete the recording of salvage. While we do not mandate the imposition of an 18-month turnaround period at this time, we expect the Company to take reasonable measures to achieve this 18-month objective.

The Company and Attorney General have raised issues concerning depreciation reserve balances, and their effect on both base rates and the CapEx. By their very nature, depreciation accruals are imprecise because they attempt to evaluate the effect of innumerable factors on a particular asset over the useful life of that asset, a process that is necessarily wrought with uncertainty and requires constant review and modification. D.P.U. 12-25, at 308; D.P.U. 200, at 20; Boston Gas Company, D.P.U. 19470, at 48-49 (1978). Consequently, a utility may have shortfalls or surpluses in its depreciation reserve. In the absence of evidence of mismanagement of a company's depreciation accrual rates, the Department will not substitute its own judgment for that of management. D.P.U. 12-25, at 90; Barnstable Water Company, D.P.U. 93-223-B at 6-7 (1994); D.P.U. 19470, at 49-50. Cf. Wannacomet Water Company, D.P.U. 13525 (1962) (company continued to use inadequate depreciation accrual rates even after Department directed corrective action, resulting in depreciation shortfall of 115 percent).

The 2015 Technical Update indicates a theoretical depreciation reserve of $1,492,421,587 as of December 31, 2014, versus a booked depreciation reserve of $1,655,620,338 as of that same date (Exh. NG-REW-2, at 40). While the Attorney General and Company each advocate various adjustments associated with retirements and cost of removal through June 30, 2015, even using the numbers offering the most favorable light to the Attorney General's position, the depreciation reserve surplus would be $189,348,096, representing 12.66

percent of the theoretical reserve provided in the 2015 Technical Update (Exh. NG-DJD-Rebuttal-2). The Department does not consider this depreciation reserve imbalance to be so excessive as to warrant corrective measures. D.P.U. 93-223-B at 5, 6-7 (no adjustment for depreciation reserve shortfall of 11.38 percent).[151] To the extent that National Grid's new salvage recording procedures produce a more accurate depiction of the role salvage plays in the development of National Grid's depreciation reserve and depreciation accrual rates, these improvements will be incorporated in the Company's next depreciation study.

Based on these considerations, the Department finds that the Company's salvage practices have not resulted in an overstatement of its rate base. The Department further finds that the Company's salvage practices have not resulted in an over-recovery of costs through the CapEx component. Accordingly, the Department declines to make any adjustment to the Company's ROE for its salvage recording practices. The Department directs National Grid to conduct a full depreciation study in conjunction with its next base rate case, and to provide that study as part of its initial filing in that case.

c. Depreciation Analysis

National Grid relies on the 2015 Technical Update as the basis for its proposed accrual rates. As described above, a technical update generally retains the parameters developed and/or approved in a company's most recent full depreciation study, and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates that have occurred since the period covered by the full depreciation

151 Even at the $200 million depreciation reserve surplus claimed by the Attorney General on brief, the surplus would represent only 13.4 percent of the 2015 Technical Update's theoretical reserve.

study (Exh. NG REW-1, at 3). The Department has accepted the use of technical updates in lieu of a full analysis. See D.P.U. 95-118, at 159-161 (Department accepted technical update of cost allocation study originally based on 1989 data). In this case, however, a number of difficulties have been identified, particularly with respect to the recording of salvage. While the Department is persuaded that the Company's salvage recording practices have not resulted in excessive depreciation surpluses, we find that National Grid's salvage and retirement recording practices are such as to raise questions as to the validity of the 2015 Technical Update. Given these concerns, the Department finds that the 2015 Technical Update does not provide sufficient basis on which to revise National Grid's depreciation accrual rates. Therefore, the Department will not use the results of the 2015 Technical Update to determine the Company's depreciation accrual rates.

Turning to the Attorney General's depreciation analysis, the Company raises a number of concerns as to its reliability. First, National Grid challenges the Attorney General's consultant for his failure to conduct a site visit of the Company's facilities. As noted above, depreciation studies rely not only on statistical analysis, but also on the judgment and expertise of the preparer. Because depreciation studies involve consideration of a company's physical assets, the Department has emphasized the importance of a physical inspection of plant assets when conducting a depreciation study. D.P.U. 19037/19037-A at 23; see also D.T.E. 05-27, at 257-258. The Attorney General's consultant obtained what he considered to be all of the necessary information from Company management through discovery, supplemented by his familiarity with other electric distribution facilities (Tr. 13, at 1446-1448). While the Department recognizes that the Attorney General conducted extensive discovery on the issue of depreciation, a site visit would have provided additional information that could have put the Company's written responses into perspective. At the very least, a site visit would have assisted in confirming the Company's responses to the witness through his own observations.

National Grid also challenges the Attorney General's comparison of the Company's ASLs with those of other Massachusetts utilities. While the Attorney General emphasized the dissimilarities of National Grid's ASLs to those of NSTAR Electric and WMECo, she did not demonstrate a significant level of familiarity with the latter two companies (Tr. 14, at 1467-1469). While different companies may have generally similar depreciation accrual rates, a greater familiarity with the characteristics of companies being used as comparisons to the company under examination will assist in identifying differing physical characteristics that may have an effect on depreciable lives and salvage factors.

Further, the Attorney General's analysis relies heavily on historical data from 2009 through 2014 (Exh. AG-WDA-9). Because of the implementation issues the Company experienced during the SAP implementation process, there were unavoidable disruptions in the processing of plant transactions (Exh. AG-3-1). These system disruptions could have affected retirement and net salvage data recorded during this period, and thus affected the statistical analyses required to estimate projection curves, projection lives, and future net salvage rates (Exh. AG-3-1).

More significantly, the Company's salvage and retirements recording practices resulted in the lack of sufficient data to develop a full depreciation study. During the first six months of calendar year 2015 (January 1, 2015 through June 30, 2015), the Company recorded approximately $56.7 million of retirements related to plant placed in service over the years prior to December 31, 2014 (RR-AG-28). While this amount was recorded prior to the test year end and is appropriately recognized in this proceeding, these retirements were not included in the Company's December 31, 2014 plant balances, the point in time used by both the Company and Attorney General for the depreciation database (RR-AG-28, at 2-3). In addition, $50,695,664 in retirements associated with plant placed into service prior to December 31, 2014 was recorded by the Company after the end of the test year, June 30, 2015 (RR-AG-28). Had this information been fully accounted for, it is likely that a more reliable depreciation analysis could have been completed.

Finally, the Attorney General's analysis is largely confined to analysis of the Company's historic database, including partial retirement data through December 31, 2014 (Tr. 13, at 1446-1447). The Attorney General's analysis does not identify any physical changes in property attributable to retirement forces acting outside of the historical data (Tr. 13, at 1447). Although the Department has recognized that consideration of polynomials, conformance indices or hazard rates, can support the robustness of a depreciation study, the Attorney General's analysis does not take these factors into consideration (Exh. AG-WDA-2). See D.P.U. 15-81/D.P.U. 15-81, at 198 n.144; D.P.U. 09-39, at 183-190. Based on the foregoing analysis, the Department finds that the Attorney General's depreciation analysis does not provide a sufficient basis on which to revise National Grid's depreciation accrual rates.

In the absence of an acceptable depreciation study from either party, the Department has relied on the use of a company's then-current depreciation accrual rates. D.P.U. 13-75, at 216; D.P.U. 10-114; D.P.U. 243, at 17. In this case, the Department has rejected the use of both the Company's 2015 Technical Update and the Attorney General's depreciation study. Therefore, the Department finds it appropriate to maintain the use of the Company's current depreciation accrual rates as derived in the 2009 Depreciation Study, and as modified in D.P.U. 09-39. The Department's calculation of the Company's depreciation expense is provided below.

d. Delayed Retirement

In order to derive a company's depreciation expense, depreciation accrual rates are applied to a company's gross depreciable plant in service. D.P.U. 14-150, at 199; D.P.U. 12-25, at 323. Both National Grid and the Attorney General agree that the Company's test year-end plant in service accounts include $52,697,141 in retirements that had been made prior to the end of the test year, but nonetheless remained in the Company's plant investment accounts (Company Brief at 161; Attorney General Reply Brief at 43). This error has no effect on the Company's rate base because when plant is retired, a corresponding entry is credited against the depreciation reserve. 18 CFR Part 101, Electric Plant Instructions, § 10(B); 220 C.M.R. § 51.01. Nonetheless, both parties agree that because depreciation expense is calculated on the basis of gross (versus depreciated) plant, an adjustment to depreciation expense remains warranted. Because this plant has been retired, the Department finds it appropriate to exclude any depreciation expense on these assets from cost of service. D.P.U. 14-120, at 36-37; Hutchinson Water Company, D.P.U. 85-194, at 7, 13 (1986).

The Company proposes to decrease depreciation expense by $1,675,769 (Company Brief at 161).[152] This adjustment appears to represent the $52,697,141 in retired plant multiplied by the Company's proposed composite depreciation accrual rate of 3.18 percent. The Attorney

152 Examination of National Grid's revised revenue requirement schedules indicates that this adjustment has not been incorporated into the Company's revenue requirement calculations (Exhs. NG-RRP-2, at 5, 27 (Rev. 3); NG-RRP-8 (Rev. 3)).

General proposes to decrease depreciation expense by $1,459,711, which she derived by multiplying the $52,697,141 in retired plant by her proposed composite depreciation accrual rate of 2.77 percent (Attorney General Reply Brief at 43). In the absence of detailed plant accounts associated with these retired assets, the Department finds that the use of a composite depreciation accrual rate produces a reasonable level of depreciation expense associated with these retirements.

Neither the Company's nor the Attorney General's selected composite rates, however, had been in use at the time of these plant retirements. The Company's current depreciation accrual rates had been in effect at the time of the retirements; applying these rates to the December 31, 2014 plant balances used as the basis of the parties' depreciation calculations produce a composite accrual rate of 3.19 percent (Exh. NG-REW-1, at 9). On this basis, the Department finds it appropriate to base the depreciation adjustment on a composite depreciation accrual rate of 3.19 percent.

The $52,697,141 in retired plant, multiplied by a composite depreciation accrual rate of 3.19 percent, produces a depreciation expense associated with delayed retirements of $1,680,847. Accordingly, the Department reduces the Company's proposed depreciation expense by $1,680,847 for delayed retirements. Because the Company has made the necessary accounting adjustments to recognize the delayed retirements, the Department declines to make any adjustment to the Company's ROE related to delayed retirements.

e. Conclusion

In order to calculate National Grid's annual depreciation expense, the Department has applied the accrual rates approved by this Order to the Company's depreciable plant balances included in rate base.[153] Based on this analysis, the Department calculates an annual depreciation expense, excluding depreciation associated with SmartGrid investments and Nantucket Electric's undersea cables, of $126,925,161 (Exh. NG-RRP-2, at 27 (Rev. 3)). Excluding the $1,680,847 in depreciation expense associated with unrecorded plant retirements produces a net overall depreciation expense of $125,244,314. This net overall depreciation expense represents an increase of $2,219,066 to the Company's test year depreciation expense, excluding that associated with SmartGrid investments and Nantucket Electric's undersea cables, of $123,025,248. National Grid has proposed an increase of $3,650,455 to its test year depreciation expense. Accordingly, the Department reduces the Company's proposed depreciation expense by $1,431,389.

F. Postage Expense

1. Introduction

During the test year, MECo booked $6,595,462 in postage expense (Exh. AG-1-34, Att. 6, at 17). The Company did not propose any adjustments to its test year postage expense, and thus included postage expense in the balance of test year O&M expenses subject to inflation ("residual O&M expense") component used to derive the inflation allowance (see Exh. NG-RRP-2, at 5-6, 23 (Rev. 3); Tr. 8, at 1358-1359).

153 For Accounts 392 (Transportation Equipment) and 396 (Power Operated Equipment), the Department applied a 6.67 percent amortization rate based on the 15-year amortization of general plant currently in use (Exh. NG-REW-2, at 46).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to recognize that the United States Postal Service ("USPS") postage rates are decreasing, and proposes that the Department reduce the Company's proposed cost of service to eliminate the postage surcharge that was in effect during the test year (Attorney General Brief at 58). The Attorney General contends that the Postal Regulatory Commission ordered the USPS to remove a 4.3 percent exigent surcharge once it had collected $4.6 billion in surcharge revenues, which was expected to occur by April 10, 2016 (Attorney General Brief at 58, citing Exh. AG-14). The Attorney General asserts that the Company's test year cost of service should thus be reduced by $283,605,[154] in order to eliminate the now-terminated postage surcharge from postage expense (Attorney General Brief at 58).

Further, the Attorney General claims that National Grid has overstated its postage expense because the Company includes postage expense in its residual O&M expense (Attorney General Brief at 58). Thus, the Attorney General argues that the Company's residual O&M expense must be reduced by $6,595,462 to recognize that postage expense has been specifically adjusted in the cost of service (Attorney General Brief at 58).

b. Company

National Grid agrees with the Attorney General's recommendation to reduce test year postage expense by $283,605 in order to account for the elimination of the USPS's exigent surcharge of 4.3 percent (Company Brief at 75). The Company also agrees to reduce its residual O&M expense by $283,605 (Company Brief at 76). However, National Grid opposes the

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[154] $6,595,462 x 0.043 = $283,605

Attorney General's proposal to exclude the remaining $6,311,857 in test year postage expenses from the residual O&M expense, because it maintains that postage rates are likely to experience inflationary pressures (Company Brief at 76).

The Company argues that the expiration of the exigent surcharge was the result of a regulatory directive to the USPS, rather than the product of reduced postal service operating costs, and it further notes that USPS rates are capped by law at the rate of inflation (Company Brief at 75, citing Exh. AG-14). Thus, National Grid contends that the Attorney General unreasonably assumes that USPS services are not subject to inflation, or that there will be no postage rate increases in the future to counteract, or mitigate, the termination of the exigent surcharge (Company Brief at 75). The Company asserts that given the "significant" strain that the elimination of the 4.3 percent surcharge will have on the USPS, the only reasonable conclusion is that postage rates will increase at the rate of inflation in the near future (Company Brief at 76). Therefore, the Company states that its adjusted postage expense should be included in the residual O&M expense (Company Brief at 76).

3. Analysis and Findings

The Department recognizes postage expense as a legitimate cost of doing business. If a postal rate increase – or, in this case, a decrease - occurs prior to the issue of an Order, that resulting rate fluctuation is eligible for inclusion in cost of service as a known and measurable change to test year expense. D.P.U. 14-150, at 206; D.P.U. 10-55, at 286; D.P.U. 08-35, at 108; D.T.E. 05-27, at 194; D.P.U. 88-172, at 23-24; Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982). The elimination of the USPS' 4.3 percent exigent surcharge already has occurred and is quantifiable, and, therefore it is a known and measurable change (Exh. AG-14).

Accordingly, the Department accepts the proposed reduction of $283,605 to test year postage expense.

Turning to the remaining $6,311,857 in postage expense that National Grid seeks to retain in the residual O&M expense, the Company's argument that postage rates could increase in the near future due to inflationary pressures or due to the expiration of the exigent surcharge fails to recognize that postage rate changes are not subject to the same general pressure of inflation. While postage increases may be capped at the level of inflation, such increases are not automatic, but rather result from actions by the Postal Regulatory Commission. D.P.U. 1720, at 21-22. Consequently, future postage rate changes are not known and measurable. Accordingly, the Department rejects the Company's proposal to include postage expense in the residual O&M expense. Therefore, the Department will remove the full test year postage expense of $6,595,462 from the Company's residual O&M expense. The effect of this adjustment is shown on Table 1 of this Order.

G. Property Tax Expense

1. Introduction

During the test year, the Company booked $56,944,818 in property tax expense (Exhs. NG-RRP-1, at 2; NG-RRP-2, at 28 (Rev.3)). National Grid seeks to increase this amount by $2,331,371 to reflect the expected level of property taxes in the rate year (Exhs. NG-RRP-1, at 38; NG-RRP-2, at 28 (Rev. 3)). The Company calculated the estimated rate year level of property tax expense by applying current municipal tax rates to the latest property valuations provided by the Company to each municipality (Exhs. NG-RRP-1 at 38, NG-RRP-2, at 28

(Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-22-3).[155] The Company excluded from its proposed property tax expense third-party reimbursements associated with the rate year estimated figure, estimated Smart Grid-related property taxes, and property taxes related to construction work in progress ("CWIP") (Exhs. NG-RRP-1, at 39; NG-RRP-2, at 28 (Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-31-11; DPU-31-12; DPU-31-13).[156]

2. Positions of the Parties

National Grid argues that its proposed municipal property tax expense is calculated in a manner that is consistent with Department precedent, as the proposed expense is based on the most recent property tax bills that the Company received from the various municipalities in which it owns property (Company Brief at 92, citing D.T.E. 02-24/25 at 123; D.P.U. 96-50, at 109). The Company notes that it calculated the proposed adjustment beginning with an adjusted test year municipal tax expense of $56,944,818, and then calculated the estimated rate year level by applying current municipality tax rates to the latest property valuations provided by each municipality (Company Brief at 92, citing Exhs. NG-RRP-1, at 38, NG-RRP-2, at 28 (Rev. 2)). No other party addressed the Company's proposed property tax expense on brief.

155 For those communities that rely on the Reproduction Cost New Less Depreciation method (see Section IX below) to determine property valuations, the Company estimated the assessed values by first determining the percentage by which the assessed value exceeded the net book value of the Company's personal property in that community for the previous tax year, and then multiplying that percentage by the net book value of the personal property in that community for the current tax year (Exhs. NG-RRP-1, at 38-39; DPU-22-3).

156 The Company received third-party reimbursements from Lightower, a former affiliate of MECo (Exh. DPU-22-11). National Grid pays property taxes on Lightower assets that are attached to the Company's poles, and Lightower reimburses the Company for the property taxes on those assets (Exh. DPU-22-11).

3. Analysis and Findings

The Department's general policy is to base pro forma level of property taxes that should be included in the revenue requirement on the most recent property tax bills from communities in which it has property. D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 14-150, at 209; D.P.U. 12-25, at 330; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). The Department holds the record open in a proceeding to receive from the utility the most current tax bills issued by cities and towns. D.P.U. 14-150, at 209; D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

The Company proposes to base its property tax expense on current tax assessments and tax rates, increased by a projection of future increases (Exhs. NG-RRP-1, at 38-39; NG-RRP-2, at 28 (Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-22-3). The Department generally has rejected the use of projected data to determine a company's property tax expenses. D.P.U. 14-150, at 209-210; D.P.U. 11-01/D.P.U. 11-02, at 280-281; D.P.U. 10-114, at 263; D.P.U. 09-39, at 244; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 109-110. Rather, the test year level of property tax expense, adjusted for known and measurable changes (i.e., the most recent property tax bills provided at the close of the record), provides the most reasonable representation of a company's property tax expense and fairly represents this component of its cost to provide service.[157] National Grid's projection of future increases of property tax expense, though derived

[157] In certain cases, such as where no property tax bills have yet been issued for a large post-test year plant addition that is being placed into service near the issue date of the Department's Order, the Department has allowed the associated property taxes to be based on the cost of the plant multiplied by the most recent property tax rate. D.P.U. 12-86, at 243-245; D.P.U. 95-118, at 148. That fact situation does not apply here. Further, the Department notes that in D.P.U. 13-75 and D.P.U. 12-25, it appears from the records that the subject company derived its post-test year property tax expense

from current tax assessments, is speculative and does not constitute a known and measurable change based on Department precedent. The Company has offered no persuasive reason to depart from our precedent here. Therefore, we decline to adopt the Company's proposed property tax calculation.

Based on the Company's most recent property valuations and actual property tax rates, National Grid's current property taxes payable to municipalities, fire districts, and water districts total $61,548,504 (Exh. DPU-22-4 & Atts.). The Department accepts this amount as known and measurable. The Department excludes from this total the property taxes associated with Lightower, Smart Grid and CWIP in the amount of $2,516,346 (Exh. NG-RRP-2, at 28 (Rev. 3)). Thus, the Company's final property tax expense is $59,032,158, which represents an increase over the test year amount of $2,087,340. The Company proposed to increase the test year amount of property tax expense by $2,331,371. Accordingly, we will reduce the Company's proposed cost of service by $244,031 ($2,331,371 minus $2,087,340).

Finally, we recognize that the recovery of property taxes is an important element of a company's operations. In addition to recovering a representative level of property tax expense through base rates, companies have proposed cost recovery mechanisms to address changes in property tax levels that occur between rate cases. For example, the Department has examined proposals to establish property tax recovery mechanisms outside of base rates to address fluctuations associated with the change in property valuation method used by municipalities.

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adjustment based on a composite rate formula. However, neither Order discusses the reasons for this treatment or contains a justification for the departure from the Department's otherwise long-standing precedent. We find that there was no express intention on the Department's part to change its long-standing precedent on property tax expense and, therefore, neither case is dispositive of our treatment of the matter here.

D.P.U. 14-150, at 269-282; D.P.U. 12-25, at 324-334 (see also Section IX below). We also have examined proposals to include the recovery of property taxes as part of a capital investment recovery tracker. D.P.U. 15-80/D.P.U. 15-81, at 54-55 (see also Section V.D.4 above). The Department acknowledges that, with the exception of application for abatements where warranted, property taxes are largely outside of a company's control. We also recognize that a consistent ratemaking approach to property taxes may increase efficiencies and reduce administrative burdens.

Given these considerations, the Department will consider whether it is appropriate to explore alternative ratemaking proposals from distribution companies to address property tax changes between rate cases. Without prejudging the question of the propriety of any alternative ratemaking proposal, a company must demonstrate in its proposal that there would be no double recovery of property tax expense. The Department will consider such proposals in the context of an individual company's base rate proceeding.

H. Insurance Expense

1. Introduction

During the test year, the Company booked $5,909,663 in insurance premium expense (Exh. NG-RRP-2, at 17 (Rev. 3)). The Company has proposed to reduce its test year cost of service by $1,033,234 based on the most recently received insurance premium billings and their respective allocations to MECo and Nantucket Electric (Exhs. NG-RRP-1, at 33: NG-RRP-2, at 17 (Rev. 3)). Of the 14 types of insurance coverage represented by the proposed adjustment, four policies (i.e., Public (Excess) Liability, Business Interruption, Property, and Property

Terrorism insurance) are provided to the Company by National Grid Insurance USA LLC ("NGI USA"), a wholly owned subsidiary of National Grid USA (Exh. NG-RRP-2, at 17 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues the Company's premium payments to NGI USA should not be included in insurance expense because (1) the Company has not demonstrated that it took reasonable measures to control costs associated with its NGI USA policies; (2) the Company has not complied with the Department's regulations on affiliate transactions; and (3) the NGI USA business interruption policy allows for double recovery (Attorney General Brief at 50-55). The Attorney General asserts that removing payments to NGI USA will result in a $2,414,233 reduction to the Company's insurance expense (Attorney General Brief at 50, citing Exh. NG-RRP-2, at 17 (Rev. 3)).

First, regarding cost containment, the Attorney General argues that the Department includes the most current cost of liability and property insurance as a reasonable cost of service. (Attorney General Brief at 50, citing Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55, at 276 (2010)). However, to be included in the cost of service, the Attorney General contends that the Company must provide evidence that it undertook reasonable measures to control property and liability insurance expense (Attorney General Brief at 50, citing D.P.U. 10-55, at 275-276; New England Gas Company, D.P.U. 08-35, at 119-120 (2009); D.T.E. 05-27, at 133-134; Boston Gas Company, D.T.E. 03-40, at 184-185 (2003)). Further, the Attorney General claims that the Company's evidence of cost containment should be provided as a narrative in its initial filing (Attorney General Brief at 51, citing D.P.U. 10-55, at 276).

The Attorney General argues that despite these requirements, the Company's prefiled testimony is limited to representations that its proposed insurance expense is known and measurable on the basis of recent insurance bills received, and there is no demonstration that the Company undertook reasonable measures to controls such expenses (Attorney General Brief at 51, citing Exh. RRP-1, at 33). Further, the Attorney General contends that during the proceedings, the Company was unable to explain: (1) the measures it took to control costs related to NGI USA; (2) the basis for selecting NGI USA as the Company's carrier for public excess liability insurance, business interruption insurance, property insurance, and property terrorism insurance; and (3) the basis for any premium charged under any insurance policy (Attorney General Brief at 51-52, citing Exh. AG-1-63; Tr. 6, at 862, 864). Based on these considerations, the Attorney General asserts that there is no evidence in the record that would support how the premiums are determined and whether or not they were reasonable or prudent (Attorney General Brief at 52, citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001), citing Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967); Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963)).

Next, the Attorney General argues that even if the Department finds that the Company provided sufficient explanation of cost containment measures, the Company's premium payments to NGI USA should not be allowed as part of its cost of service because the payments violate the Department's affiliate transaction regulations (Attorney General Brief at 52).

According to the Attorney General, NGI USA is an affiliate of the Company, as defined by G.L. c. 164, § 85 ("§ 85") (Attorney General Brief at 53).[158]

In particular, the Attorney General contends that NGI USA was established to provide insurance coverage to National Grid's operating companies, thus being created to serve and benefit the Company (Attorney General Brief at 53, citing RR-AG-33). Further, the Attorney General claims that the Company discusses its "insurance captives" and "insurance subsidiary undertakings" in its annual reports to shareholders (Attorney General Brief at 53, citing Exh. AG-1-2-3(1g), Att., at 119, line 2-3, 133, 190).

The Attorney General asserts that Department regulation[159] and good utility practice require evidence that any affiliate services are priced at no more than market value. According

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158 G.L. c. 164, § 85, provides, in pertinent part:

> . . . "affiliated company" shall mean any corporation, society, trust, association, partnership or individual (a) controlling a company subject to this chapter, either directly, by ownership of a majority of its voting stock or of such minority thereof as to give it substantial control of such company, or indirectly, by ownership of such a majority or minority of the voting stock of another corporation or association so controlling such company; or (b) so controlled by a corporation, society, trust, association, partnership or individual controlling as aforesaid, directly or indirectly, a company subject to this chapter; or (c) standing in such a relation to a company subject to this chapter that there is an absence of equal bargaining power between the corporation, society, trust, association, partnership or individual and the company so subject, in respect to their dealings and transactions.

159 220 C.M.R. § 12.04(3) provides:

> 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.

to the Attorney General, the Department is required to carefully scrutinize affiliate transactions because "the exercise of control and the absence of an arm's length bargaining" may lead to "'excessive charges for services . . . .'" (Attorney General Brief at 53, citing D.P.U. 12-86, at 11; Public Utility Holding Co. Act of 1935, P.L. No. 333 (1935), 49 Stat. 803, § 1 (1935); Report of the Special Committee on Control and Conduct of Public Utilities, (1930 H. 1200, § 31)). Consequently, the Attorney General argues that if affiliate costs are excessive, they should be excluded from the revenue requirement (Attorney General Brief at 53-54, citing G.L. c. 164, § 94B)). In this regard, the Attorney General contends that National Grid failed to offer any evidence to demonstrate that the amount of premiums charged to the Company by NGI USA are at or below the market price (Attorney General Brief at 54, citing Exh. NG-RRP-2, at 17 (Rev. 3)). Thus, the Attorney General asserts that the Department should disallow these payments to be included in rates and the cost of service should be reduced by $2,414,233 (Attorney General Brief at 54).[160]

Finally, the Attorney General argues that the Company's cost for its business interruption insurance should be disallowed because a claim for loss of income under the policy would amount to double recovery (Attorney General Brief at 54). According to the Attorney General, the Company already is made whole for reductions to income through its RDM (Attorney General Brief at 54). Specifically, the Attorney General contends that National Grid pays annual premiums of $103,968 for a business interruption policy that indemnifies the Company for

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160 The Attorney General provides a breakdown of the premiums as follows: (1) $965,005 in Public (Excess) Liability Insurance premiums; (2) $103,968 in Business Interruption Premiums; (3) $1,296,816 in Property Insurance premiums; and (4) $48,444 in Property Terrorism Insurance premiums (Attorney General Brief at 54, citing Exh. NG-RRP-2, at 17 (Rev. 3)).

reductions to income as a result of the interruption or interference with the business (Attorney General Brief at 55, citing Exh. NG-RRP-2, at 17 (Rev. 3); RR-AG-30, Att. at 49). The Attorney General notes that "income" is defined in the policy as "the sum of gross earnings and/or sales and/or income and/or revenue derived from the [b]usiness." (Attorney General Brief at 53, citing RR-AG-30, Att. at 50). The Attorney General reasons that because National Grid's RDM makes the Company whole for reductions in revenues, the Company receives the same amount of revenue for its distribution services regardless of whether there is an interruption to the Company's operations (Attorney General Brief at 55, citing Exhs. NG-MLR-1; NG-RRP-1). Consequently, the Attorney General argues that a claim under the business interruption policy for reduced income would amount to a double recovery from customers (Attorney General Brief at 55). Therefore, the Attorney General asserts that costs for the Company's business interruption policy should be excluded from insurance expense and the Company's proposed cost of service should be reduced by $103,968 (Attorney General Brief at 55).

b. Company

First, regarding cost containment, National Grid disputes the Attorney General's claim that the Company has not demonstrated that it undertook reasonable measures to control costs associated with NGI USA, and challenges the Attorney General's position that such a demonstration is required a part of the initial filing (Company Brief at 61). The Company contends that in each of the cases relied on by the Attorney General, the petitioner sought an increase to test year insurance expense, and that the Department's reference to "reasonable efforts to control costs" pertained to the requested increase in expense (Company Brief at 61, citing D.P.U. 10-55, at 274-276 (requesting a post-test year increase of $376,488); D.P.U. 08-35, at 119-120 (requesting a post-test year increase $225,993); D.T.E. 05-27, at 132 (requesting a post-test year increase of $94,997, subsequently adjusted); D.T.E. 03-40, at 184-185 (requesting a post-test year increase of $607,287)). National Grid notes that, in this case, the Company is seeking to decrease its test year expense, which, in itself, demonstrates that the Company has controlled costs so that the rate-year expense is less than the test year expense (Company Brief at 61). According to National Grid, there is no basis for disallowance of a significant amount of expense on the basis that the Company had an affirmative obligation to demonstrate cost control in the prefiled testimony where there is no increased cost requiring such demonstration (Company Brief at 63).

National Grid also challenges the Attorney General's claim that during the proceedings the Company was unable or failed to adequately respond to inquiries regarding the selection of NGI USA or the basis for recovery of insurance expense (Company Brief at 62-63, citing Exh. AG-1-63; Tr. 6, at 862-865; RR-AG-33). In this regard, National Grid notes that the Attorney General made no attempt to examine the reasons that insurance expense is decreasing (Company Brief at 63-64). The Company asserts that there is no basis for disallowance of insurance expense where there is no reasonable inquiry made into the proposed adjustment (Company Brief at 63).

Turning to its use of NGI USA, National Grid argues that the Department has previously found that the procurement of insurance coverage through "captive" or affiliated insurance companies can be effective to reduce costs to customers (Company Brief at 64). According to the Company, captive insurance companies are known to be a cost-efficient alternative to risk transfer because the arrangement leverages the use of reinsurance markets and puts the captive insurance carriers in competition against markets that underwrite in the conventional direct insurance marketplace, thereby driving down the cost below what would be available solely by using conventional direct writing insurers (Company Brief at 64, citing Bay State Gas Company, D.P.U. 13-75, at 181, 193-194 (2013)).

Second, the Company argues that there is no evidence that the premium cost charges by NGI USA are "excessive" or above market (Company Brief at 64). According to the Company, mandates of NGI USA include providing insurance coverage to National Grid USA's operating companies at rates that are at or below those that can be achieved in the commercial insurance markets, as well as enhanced policy coverage beyond what is available in those markets (Company Brief at 64-65, citing RR-AG-33).

Moreover, the Company contends the Department does not routinely review or render determinations on whether insurance premiums charged by affiliates are at or below the market price where the petitioning utility is not asking for any increase in the test year amount (Company Brief at 65). The Company claims that a petitioning company cannot foresee every specific area of inquiry of interest to the other parties, and that the law places some obligation on other parties to raise issues during the preceding so that there is an opportunity for rebuttal (Company Brief at 65, citing Fitchburg Gas & Electric Light Co. v. Department of Public Utilities, 375 Mass. 571, 578 (1978); NYNEX, D.P.U. 86-33-G at 74 (1989); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983)). Therefore, the Company asserts that its arrangement with NGI USA does not result in a violation of the Department's affiliate regulations (Company Brief at 65).

Finally, the Company disputes the Attorney General's claim that the business interruption policy constitutes "double recovery" of expenses (Company Brief at 66). In this regard, the Company argues that it would never make an insurance claim, nor would it be lawfully eligible for a claim of lost revenues, where the revenues were recovered through the revenue-decoupling mechanism (Company Brief at 66). Further, the Company contends that the Attorney General ignores the other coverage protections that are not driven by reductions in consumption and would not be recovered through the ratemaking process, primarily relating to continuing operations, contractual agreements and other items (Company Brief at 66, citing RR-AG-30, Att.). National Grid claims that it would be unreasonable and imprudent for the Company to forego business interruption coverage and that the ultimate cost of not carrying such insurance would fall on the customers (Company Brief at 66-67). For these reasons, the Company concludes there is no unwarranted cost or "double recovery" of revenue loss that occurs due to the availability of this policy (Company Brief at 67).

3. Analysis and Findings

a. Introduction

Under current ratemaking practice, the Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; North Attleboro Gas Company, D.P.U. 86-86, at 8-10 (1986); D.P.U. 84-94, at 44. The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185.

b. Cost Containment

Concerning National Grid's efforts to control costs associated with its NGI USA policies, the cases relied on by the Attorney General each involve proposed increases to test year insurance expense. D.P.U. 10-55, at 274-276 (requesting a post-test year increase of $376,488); D.P.U. 08-35, at 119-120 (requesting a post-test year increase $225,993); D.T.E. 05-27, at 132 (requesting a post-test year increase of $94,997, subsequently adjusted); D.T.E. 03-40, at 184-185 (requesting a post-test year increase of $607,287). In this case, the Company is seeking to decrease test year insurance expense by $1,033,234 (Exhs. NG-RRP-1, at 33; NG-RRP-2, at 17 (Rev. 3)). In this instance, the Department finds that the reduced premium billings from NGI USA and the Company's proposed reduction in the cost of service constitute sufficient evidence that the Company has controlled its insurance costs.[161]

As stated above, the Department considers measures by utilities to control property and liability insurance expense to be important in reviewing a company's cost of service. The Department's review of these cost control measures typically focused on instances of increased costs. Efforts by utilities to manage their insurance coverage with a consideration of costs also are important where premium costs are decreased. Thus, the Department requires companies in their base rate cases to identify reasonable measures to control property and liability insurance expenses, whether the insurance costs are increasing or decreasing.

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161 While the Company's insurance expense has increased since the 2008 test year used in its previous rate case, we are unable to conclude that an increase in costs over an eight-year period is in itself evidence of a failure in cost-containment efforts.

c. Affiliate Transactions

The Attorney General argues that, even if the Department finds that the Company demonstrates cost-control measures associated with its NGI USA insurance policies, the Company's premium payments to NGI USA should not be allowed as part of its cost of service because they violate the Department's affiliate transaction regulations (Attorney General Brief at 31). Specifically, the Attorney General claims that the Company has not demonstrated that its payments to NGI USA are not excessive, and that there is no evidence that the amount NGI USA charges the Company for premiums are at or below market price (Attorney General Brief at 31).

NGI USA provides insurance coverage to National Grid as a "captive" or affiliate insurance company. The Department previously has found that procurement of insurance coverage through "captive" or affiliated insurance companies can be effective to reduce costs to customers. Captive insurance companies are known to be a cost-efficient alternative to risk transfer because the arrangement leverages the use of reinsurance markets and puts the "captive" insurance carriers in competition against markets that underwrite in the conventional direct insurance marketplace, thereby driving down the cost below which would be available by solely using conventional direct writing insurers. Bay State Gas Company, D.P.U. 13-75, at 181, 193, 194; see also Boston Edison Company, D.P.U. 376, at 13-14 (1981).

We affirm our findings regarding the benefits of the procurement of insurance coverage through "captive" or affiliate insurance companies. Given this precedent and the absence of evidence in this case of excessive or above-market premiums paid by the Company to NGI USA, the Department allows these costs and finds no grounds to assert a violation of the Department's affiliate transaction rules. Further, within a substantial range, business decisions are matters for a company's determination. Fitchburg Gas and Electric Light Company, 375 Mass. 571, 578 (1978). However, when a company's determination is challenged, it must come forward with evidence to support its decisions and show that they are not inconsistent with valid policies of the Department. 375 Mass. at 578-579. Regarding the use of affiliate insurance companies, the Department has not established any specific filing requirements or analysis for companies to support the associated insurance expenses. Also, the Attorney General's challenge was on brief, eliminating the opportunity for the Company to present evidence in support of its procurement of insurance coverage from NGI USA. See D.P.U. 95-118, at 143; The Berkshire Gas Company, D.P.U. 92-210, at 102 (1993); Commonwealth Gas Company, D.P.U. 87-122-B at 54 (1989). Based on the circumstances of this case, we rely on the business judgment of National Grid in procuring insurance coverage from NGI USA, and we do not reduce the Company's cost of service based on the challenge of the Attorney General.

Although the Department continues to recognize the benefits of jurisdictional companies' procuring insurance through affiliate insurance companies, we find that our review of this type of arrangement would be served by a company's production of specific information. Accordingly, where a company procures insurance coverage from an affiliate insurance company, the jurisdictional company shall in its base rate case provide the following information: (1) whether comparative studies are performed to identify the relationship between affiliate premiums and premiums available in commercial markets; (2) whether such a comparative analysis was performed during the test year; (3) whether there is documentation that the affiliate insurance company's premiums are lower than premiums to the company for comparable coverage in the commercial insurance markets; and (4) whether affiliate insurance providers are able to provide broader coverage to the company than what is commercially available in the marketplace.

d. Business Interruption Policy

Finally, the Attorney General challenges the need for the Company's business interruption policy, because of the potential for "double recovery" through costs both recovered under the policy and recovered through the RDM (Attorney General Brief at 54). On a basic level, business interruption insurance covers the loss of income that a business suffers after a disaster. Under the coverage provided by NGI USA, National Grid is indemnified for "actual loss sustained" resulting directly from interruption of or interference with National Grid's operations, activities, or services due to an "occurrence"[162] affecting National Grid's property (RR-AG-30, Att. at 9, 27, 49). Actual loss sustained includes reduction in income, continuing obligations payable following the interruption or interference, the amount of a loss under a contractual agreement payable as a result of the interruption or interference, and extra expense incurred to continue usual operations, which are over and above normal costs to conduct operations (RR-AG-30, Att. at 49-51).

Based on our review of the record, we find that the Company's business interruption insurance coverage would not lead to double recovery. As National Grid represented, the Company could not make a claim for lost under its business interruption policy where the

162 An occurrence includes such events as windstorm, tornadoes, hail, rainstorm, electrical storm, cyclones, hurricanes, similar storms and systems of winds of a violent and destructive nature, earthquake shock, volcanic eruption, tsunami, seaquake, tidal wave, sub-sea mud slide (RR-AG-30, Att. at 10).

revenues were recovered through its RDM.[163] In addition, the Company's policy covers more than a reduction in income, such as obligations payable following the interruption or interference, losses under contractual agreements that are payable as a result of the interruption or interference, and expenses incurred over and above the usual costs of operations (RR-AG-30, Att. at 49-51). These losses are not associated with customers' usage or distribution revenues.

Also, as stated above regarding National Grid's procurement of insurance coverage from NGI USA, with the absence of evidence in this case of double recovery or unreasonable insurance costs, the Department relies on the business judgment of National Grid in procuring business interruption insurance. Therefore, the Department does not reduce the Company's cost of service for its costs for business interruption insurance.

e. Conclusion

Based on the foregoing, the Department finds that the Company's insurance expense premiums are based on actual policy rates, and are thus known and measurable. Therefore, the Department approves the Company's proposed adjustments. Accordingly, the Department accepts the Company's proposal to reduce its test year insurance expense by $1,033,234.

I. Rate Case Expense

1. Introduction

Initially, the Company estimated it would incur $1,512,785 in rate case expense (Exhs. NG-RPP-1, at 35; NG-RRP-2, at 22). Based on its final invoices and projected costs to

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163 Under the Company's RDM, the Department establishes the Company's target annual distribution revenues in base rate case. On an annual basis, the Company reconciles its actual distribution revenues to the target revenues, and collects from customers an amount less that its target revenues (or returns to customers an amount greater that its target revenues) (Revenue Decoupling Mechanism Provision, M.D.P.U. No. 1289).

complete the compliance filing, the Company proposes a final rate case expense of $1,245,607 (Exh. NG-RRP-2, at 22 (Rev. 3)). National Grid's proposed rate case expenses include costs related to legal support services, miscellaneous expenses associated with preparing the rate case (e.g. compact disc and flash drive preparation, bound copies of filings, tabs, couriers, etc.), and expert services related to the following: (1) marginal distribution cost study; (2) depreciation study; and (3) cost of capital/ROE (Exhs. NG-RRP-2, at 22 (Rev. 3); DPU-7-1; DPU-7-14 (Supp. 2); RR-AG-32, Atts.).

National Grid proposes to normalize its rate case expense over a period of five years (Exhs. NG-RRP-1 at 35; DPU-7-20). The Company argues that this normalization period is consistent with the provisions of § 94, which requires electric companies to file general rate cases no less frequently than at five-year intervals (Exhs. NG-RRP-1, at 35; DPU-7-20). Normalizing the Company's proposed rate case expense of $1,245,607 over five years produces an annual expense of $249,121 (Exh. NG-RRP-2, at 26 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has not met its burden to justify full recovery of rate case expense in this proceeding (Attorney General Brief at 60). Specifically, the Attorney General contends that the Company failed to limit the costs associated with outside witnesses, particularly in the areas of cost of capital/ROE and legal services, and failed to offer a proposal for shareholders to bear a portion of rate case expenses (Attorney General Brief at 61). According to the Attorney General, a request for proposals ("RFP") process is insufficient to adequately control rate case expense (Attorney General Brief at 61).

With respect to the retention of outside witnesses, the Attorney General argues that because National Grid is a large company, it should have assigned more internal company employees to sponsor testimony and more internal counsel to perform legal work on the rate case (Attorney General Brief at 61). Thus, the Attorney General asserts that the Department should exercise its discretion and reduce recovery of expenses associated with the Company's cost of capital witness and outside legal services by 50 percent (Attorney General Brief at 61).

Alternatively, the Attorney General recommends that shareholders should be assigned at least 30 percent of the cost of outside legal services (Attorney General Brief at 62; Attorney General Reply Brief at 34). In this regard, the Attorney General notes that the Company, after an RFP process, retained a legal service provider whose proposal was 30 percent higher than the next lowest bidder (Attorney General Brief at 62-63; Attorney General Reply Brief at 34). Further, she contends that the next highest bidder had substantial utility experience and prior experience practicing before the Department (Attorney General Brief at 62; Attorney General Reply Brief at 34). The Attorney General asserts that because the Company failed to show that the next highest bidder could not perform the work necessary to litigate this rate case shareholders should be responsible for 30 percent of the costs associated with the retained legal service provider (Attorney General Brief at 62-63; Attorney General Reply Brief at 34).

Finally, the Attorney General rejects any notion that predicting actual costs is difficult or that the bids provided by the selected legal service provider and the next highest bidder were difficult to compare because the providers used different "inputs and assumptions" in developing their respective bids (Attorney General Reply Brief at 34-35). According to the Attorney General, National Grid should have provided adequate inputs and assumptions for the bidding firms to use in their estimates so that the Company could have an objective benchmark of comparison (Attorney General Reply Brief at 35). Further, she asserts that if the price structures and fees of these bids are truly incomparable because of widely different inputs and assumptions, then the Company did not conduct a "fair, open, and transparent" competitive bidding process (Attorney General Reply Brief at 35).

b. Company

The Company argues that it contained rate case expenses in several ways. First, the Company contends that it used internal personnel and resources whenever practicable given internal expertise and existing workload requirements (Company Brief at 80, 82). Second, National Grid claims that for certain non-routine work that required the use of outside consultants with specialized expertise or experience, the Company engaged in an RFP process to select the most qualified and cost-effective service provider (Company Brief at 80, 84-89).

With respect to the RFP process, the Company argues that it used an internal review committee to evaluate bids based on price and non-price factors, including vendor qualifications; relevant experience; capabilities and personnel to support the rate petition; proposed fee structure; and other factors (Company Brief at 79, citing Exh. DPU-7-2).[164] The Company concedes that it did not select the lower cost bidder for its depreciation analysis, cost of capital/ROE analysis, and legal services provider (Company Brief at 80, citing Exh. DPU-7-3).

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164 In particular, the Company notes that each outside service provider executed a Project Statement, which contained a detailed scope of work with a "not-to-exceed" cost amount (Company Brief at 82, citing Exhs. DPU-7-15; DPU-7-16). According to the Company, any potential increase in costs would be reviewed, subject to negotiation and documented through a project change request (Company Brief at 82). Further, the Company notes that its engagement with outside service providers included written policies designed to control travel, lodging, meals and other similar expenses, and prohibited markups on expenses or direct costs (Company Brief at 82).

However, the Company argues that it gave proper consideration to price and non-price factors in selecting reasonably priced service providers who possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks to be performed (Company Brief at 88, citing D.P.U. 13-75, at 241).

More specifically, National Grid justifies its retention of its depreciation-related service provider based on efficiencies gained through a past relationship and the provider's knowledge of the Company's operations (Company Brief at 80, citing Exh. DPU-7-3). With respect to its cost of capital/ROE service provider, the Company contends that a strict cost comparison among bids would inappropriately favor a bidder who underestimated the level of time and effort for litigation in this case (Company Brief at 80, citing Exh. DPU-7-3). Thus, the Company claims that it reviewed average hourly labor rates for different bidders and compared them on a normalized level of time, which resulted in the selected service provider having the lowest effective bid (Company Brief at 80, citing Exh. DPU-7-3).

Regarding legal counsel, the Company argues that it selected a legal services provider that has extensive rate case experience in Massachusetts, is thoroughly familiar with the Department's practices for rate case management, and offered a fee structure that was competitive with other RFP respondents (Company Brief at 80-81, citing Exh. DPU-7-3). On this last point, National Grid argues that when analyzed on a standard hourly fee basis, the selected service provider offered hourly rates that were significantly lower than other bidders, and its estimate of labor hours was more consistent with the actual number of hours needed to fully support the rate case (Company Brief at 85, citing Exh. DPU-7-3, Att.). National Grid rejects the notion that choosing a legal service provider based solely on estimated costs is appropriate because each bidder uses its own inputs and calculus in developing bids, and total number of hours actually required to litigate the case is largely a function of the number of discovery requests received and the number and nature of the issues raised by intervenors, factors over which the Company has no control (Company Brief at 86). Thus, the Company asserts that a "hard cap" for recovery of rate case expense based on cost estimates is punitive (Company Brief at 86). Further, National Grid contends that there is no evidence to suggest that selecting a different legal service provider would have resulted in a lower actual costs, particularly since the actual hours that ultimately are spent litigating the case are unknown at the time that the RFP responses are submitted (Company Brief at 87).

Finally, National Grid argues that it properly considered shareholder responsibility for a portion of rate case expense (Company Brief at 82-83, citing Exh. DPU-7-20). In this regard, the Company contends that shareholders already bear a portion of rate case expense because: (1) the Department's ratemaking treatment of rate case expense does not guarantee dollar-for-dollar recovery; (2) if the Company files another base rate case before the expiration of the normalization period attributable to the rate case expense in this proceeding, the Company will not fully recover all of such rate expense; (3) to the extent rate case expense is not fully recovered, the Company's earned rate of return will be negatively impacted, which has a direct impact on shareholders; and (4) even if the normalization period matches the period between rate cases exactly, the Company and its shareholders are not reimbursed for actual carrying costs (Company Brief at 83, citing Exhs. DPU-7-20; AG-8-19).[165]

Based on these considerations, the Company asserts that there is no basis for the Department to reduce the Company's rate case expense as recommended by the Attorney General (Company Brief at 85, 89).

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 been actually 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 227.

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 241-242; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192. All companies are on notice that the risk of non-recovery of rate case expense 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,

165 The Company also argues that, in this particular case, shareholders are bearing the costs related to the PwC Report, which was discussed above in Section III (Company Brief at 83).

at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also D.P.U. 93-223-B at 16-17.

b. Competitive Bidding

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-159; 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 the 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 an 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. National Grid's Request for Proposal Process

The Company conducted a competitive bidding process to retain outside consultants associated with its: (1) marginal distribution cost study; (2) depreciation analysis; (3) cost of capital/ROE analysis; and (4) legal services (Exhs. DPU-7-1; DPU-7-6; AG-8-14). The Company bears the burden to demonstrate that its choices of outside consultants and legal service provider are reasonable and cost effective. D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153.

As an initial matter, we note that the Company evaluated the capabilities of its internal staff, including access to data, expertise, and experience, in determining whether to retain the selected outside service providers (Exh. DPU-7-5). We find that the Company's decision to retain outside consultants, rather than using internal personnel, to perform these tasks is reasonable given the complexity of the issues and the overall scope of this rate case.

The Company received at least three bids in each of the four categories for which it sought outside consultant services (Exhs. DPU-7-1, at 2; DPU-7-2). The record demonstrates that bids were internally reviewed through an analysis of a number of factors including strength of proposals, familiarity with the Company's operations, industry experience, cost, approach, and project management (Exh. DPU-7-2 & Atts.).

The Department has reviewed the bids associated with the four categories of rate case expense for which the Company conducted a competitive solicitation, as well as the scoring and evaluation material submitted by the Company and other evidence regarding the selection process, and we have considered the related arguments of the parties (Exhs. DPU-7-1 & Atts.; DPU-7-2 & Atts.; DPU-7-3; DPU-7-5). We are satisfied that the selection process was appropriate and that the bidders were scored and evaluated in a reasonable and equitable manner. We decline to substitute our judgment for that of the Company in evaluating each bidder against each criterion. Further, we find that National Grid gave appropriate weight to the billing structures of the various bidders and any differences among them, and considered other important price factors, such as price caps and other cost-containment features, and important non-price factors as well, such as familiarity with Department precedent and the Company's operations (Exhs. DPU-7-1, Atts.; DPU-7-2) & Atts.; DPU-7-3; DPU-7-5; DPU-7-15; DPU-7-16; DPU-7-17).

The Company concedes that it did not select the lowest cost bidder for its depreciation consultant, cost of capital/ROE witness, or legal services provider (Company Brief at 80, citing Exh. DPU-7-3). The Attorney General challenges the retention of National Grid's cost of capital/ROE consultant and legal services provider because of this purported deficiency (Attorney General Brief at 61-62; Attorney General Reply Brief at 34).

The Department does not require a company to choose the lowest bidder, provided that the company adequately justifies its decision to do so. See D.P.U. 10-70 at 153; D.T.E. 03-40 at 153. As an initial matter, we note that although all three selected providers were not the lowest bidders, we conclude that the amount of the respective bids was not unreasonable or disproportionate to the overall scope of work provided by these providers (see Exhs. DPU-7-1, Atts. 2(c); 3(e), 4(b); DPU-7-14, Atts. 2, 3 (Supp. 2)).

With respect to the depreciation analysis, the record shows that the selected provider had performed similar work for the Company in the past and compiled historical asset data necessary to perform services in this case (Exhs. DPU-7-3, at 1; DPU-7-5, at 1-2). As such, it is reasonable to expect that the foundational process required for a new provider would be time consuming and require costs that the selected service provider did not incur (Exh. DPU-7-3, at 1). Based on these considerations, we conclude that it is unlikely that an alternative service provider could duplicate these specialized services for a lower cost. Therefore, we find that the Company's selection of its depreciation-related consultant was reasonable, prudent and appropriate.

With respect to the cost of capital/ROE consultant, the record shows that the bids detailed different estimates of anticipated effort for the adjudicatory phase of the proceeding with no caps on cost (Exhs. DPU-7-1, Atts. 3(a) through (e); DPU-7-2, Att. 3; DPU-7-3, at 1). As a result, the Company performed a more detailed analysis of the bids and cost comparison (Exhs. DPU-7-2, Att. 3; DPU-7-3, at 2). The result of this analysis shows that the selected bidder compares favorably with the remaining bidders in terms of cost (Exh. DPU-7-2, Att. 3; DPU-7-3, at 2). In addition, the Company considered level of expertise, experience and litigation support that the selected provider would contribute to the proceeding, as well as the prior relationship and familiarity with the Company's operations (Exhs. DPU-7-2, Att. 3; DPU-7-3, at 2). In light of these factors, we find that the Company's selection of its cost of capital/ROE consultant was reasonable, prudent and appropriate.

Finally, with respect to the legal services provider, we find that National Grid gave appropriate weight to the billing structures of the various bidders and any differences among them, and considered other price factors, such as price caps, estimated hours of labor, and cost-containment features (Exhs. DPU-7-2 & Att. 4; DPU-7-3, at 2 & Att.). We are not persuaded by the Attorney General's suggestion that a comparison of cost estimates should have been the driving factor in the Company's decision. Rather, we conclude that National Grid appropriately considered other important factors in selecting its legal service provider, including the selected provider's rate case experience, knowledge of the electric industry and Department precedent, previous close working relationship with the Company, and familiarity with Company operations (Exhs. DPU-7-2 & Att. 4; DPU-7-3, at 2 & Att.). Further, as noted above, the cost estimate provided was not unreasonable or disproportionate to the overall scope of work provided by this provider, particularly in light of the complexity of the case and the number of issues presented (see Exhs. DPU-7-1, Att. 4(b); DPU-7-14, Atts. 2, 3 (Supp. 2)). Based on these considerations, we find that the Company's selection of its legal service provider was reasonable, prudent and appropriate.

For all of the foregoing reasons, we conclude that the Company conducted a fair, open and transparent RFP process in selecting all of its outside consultants and legal services provider. Further, we find that the Company provided a sufficient justification for not selecting the lowest bidder for its depreciation analysis, cost of capital/ROE consultant, and legal services provider. Accordingly, we decline to adopt the Attorney General's recommendations to disallow a portion of rate case expense recovery on the basis that the Company failed to control costs by not selecting the lowest bidder.

c. Various Rate Case Expenses

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by the Company and finds that such invoices are properly itemized (Exh. DPU-7-14, Att. 1 (Supp. 2)). Further, we find that the total costs associated with each service provider were reasonable, appropriate, proportionate to the overall scope of work provided, and prudently incurred (Exh. DPU-7-14, Att. 1 (Supp. 2)).

In addition, the Company seeks to include proposed miscellaneous costs of $133,603.64 (Exh. DPU-7-14, Att. 3 (Supp. 2)). These miscellaneous costs include costs related to case production expenses (Exh. DPU-7-14, Att. 3 (Supp. 2)). Neither the Attorney General nor any other party challenges the inclusion of these costs in rates. Nevertheless, the Company bears the burden of demonstrating that these costs are reasonable and appropriate and were prudently incurred. D.P.U. 10-114, at 220, 224-225; D.P.U. 95-118, at 115-119.

The Department has reviewed the invoices provided by the Company for these miscellaneous costs and finds that such invoices are properly itemized (Exh. DPU-7-14, Att. 1 (Supp. 2)). Further, given the nature and scope of this complex proceeding, the Department finds that these miscellaneous costs are reasonable and appropriate and were prudently incurred (Exh. DPU-7-14, Att. 1 (Supp. 2)).

d. Fees for Rate Case Completion

The Company has included $30,000 in its proposed rate case expense as a compliance phase flat fee for legal services (Exhs. DPU-7-14, Att. 2 (Supp. 2)). This amount is included in the proposed final rate case expense amount of $1,245,607 (Exhs. DPU-7-14, Att. 2 (Supp. 2); DPU-7-14, Att. 3, at 1 (Supp. 2)).

The Department's long-standing precedent allows only known and measurable changes to test year expenses to be included as adjustments to cost of service. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161; D.T.E. 02-24/25 at 195; D.T.E. 98-51 at 61-62. Proposed adjustments based on projects or estimates are not known and measurable, and recovery of those expenses is not allowed. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not preclude recovery of fixed fees for completion of compliance filing work in a rate case but the reasonableness of the fixed fees must be supported by sufficient evidence. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts for services to complete a case after the record closes and briefs are filed, a company may qualify to recover such expenses. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Documented and itemized proof is a prerequisite for recovery. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to a compliance filing. D.P.U. 10-114, at 237; D.P.U. 10-55, at 338.

The Department has reviewed the Company's basis for its proposed fixed fee and has determined that this fixed fee is reasonable and supported by sufficient evidence (Exh. DPU-7-1, Att. 4(b)). Accordingly, we allow the Company to recover these costs as part of its rate case expenses.

e. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the experience of 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; D.P.U. 1490, at 33. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include in the cost of service a representative annual level of rate case 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).

The Company calculates a normalization period of six years, and states that its calculation is consistent with Department precedent (Exh. AG-8-20, Att.). However, the Company proposes a rate case expense normalization period of five years based on the directives set forth in § 94 that electric companies shall file general rate cases no less frequently than at five-year intervals (Exh. DPU-7-20). Neither the Attorney General nor any other party challenges the Company's proposal to normalize rate case expense over the five year period.

As an initial matter, we note that, under Department precedent, the Company incorrectly calculated its normalization period of six years (see Exh. AG-8-20, Att.). The correct application of Department precedent would result in a normalization period of eight years.[166] However, we find that the § 94 requirement for electric companies to file rate cases every five years effectively caps the normalization period at five years. Therefore, in instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, such as in the instant case, we will instead impose a five-year normalization period.[167] Accordingly, the Department approves the Company's normalization period of five years.

f. Requirement to Control Rate Case Expense

The Attorney General argues that the Department should reduce a portion of National Grid's recovery of rate case expense because the Company failed to adequately control costs (Attorney General Brief at 62; Attorney General Reply Brief at 34). Based on our findings above, we decline to adopt the Attorney General's recommendations on this basis. Further, the Company has shown that it considered the issue of cost-sharing rate case expense between ratepayers and shareholders, and we find that the Company has provided sufficient justification for not proposing that shareholders bear a portion of the rate case expense incurred in this proceeding (Exhs. DPU-7-20; AG-8-19).

Since the establishment of the requirement for companies to propose a rate case expense cost-sharing arrangement, the Department has had an opportunity to evaluate companies'

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166 Based on the Company's filing dates for the last four rate cases, between D.P.U. 15-155 and D.P.U. 09-39, the interval is 5.5 years; between D.P.U. 09-39 and D.P.U. 95-40, the interval is 14.16 years; and between D.P.U. 95-40 and D.P.U. 92-78, the interval is 3 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 years/3 = 7.55 (rounded to eight).

167 Where a normalization period calculated pursuant to Department precedent is less than five years, this lesser period shall apply.

responses. See, e.g., D.P.U. 14-150, at 224-227; D.P.U. 13-90, at 177-181; D.P.U. 13-75, at 245-246; D.P.U. 12-25, at 204-207. In each instance, we have accepted a company's decision not to propose a specific cost-sharing arrangement. As noted, we accept National Grid's explanation in this case as well.

We recognize that the Department's ability to disallow a company's recovery of rate case expense for failure to adhere to our strict requirements concerning competitive bidding, or for failure to pursue other reasonable cost-containment measures, or for failure to properly itemize rate case expense invoices, provides a sufficient incentive for companies to control rate case expense. Further, we recognize that the nature of normalized rate case expense recovery (i.e., not dollar-for-dollar recovery) is such that shareholders already absorb a portion of rate case expense, even in light of the § 94 requirement for electric companies to file rate cases every five years (see Exh. DPU-7-20).

Based on these considerations, we no longer will require companies to file a specific proposal for shareholders to bear a portion of rate case expense. However, we cannot overemphasize that this decision in no way minimizes our focus on the importance of cost containment. We will continue to closely scrutinize the RFP process to ensure that it is rigorous and demonstrates that outside service providers chosen are reasonable and cost effective. See D.P.U. 14-150, at 226-227; D.P.U. 13-90, at 177-178. In addition to a thorough RFP process, the Department expects cost containment provisions to be included in rate case expense and companies to be aggressive in their cost control measures. D.P.U. 14-150, at 226-227; D.P.U. 13-90, at 177-178. The Department will continue to exercise its discretion to disallow recovery of rate case expense where a company fails to adhere to these requirements, as well as in instances where the amount of overall rate case expense appears to be excessive or disproportionate to the work performed.

4. Conclusion

The Company originally proposed an annual rate case expense of $302,557 based on an estimated total rate case expense of $1,512,785 (Exhs. NG-RPP-1, at 35; NG-RRP-2, at 22). The Company subsequently proposed to reduce the annual level of recovery by $53,436 to $249,121 based on a revised total rate case expense of $1,245,607 (Exh. NG-RRP-2, at 22 (Rev. 3)). Based on our findings above, the Department accepts a total rate case expense of $1,245,607. We also accept a normalization period of five years, which results in an annual level of rate case expense of $249,121. Accordingly, we need not make any further adjustments to the Company's rate case expense.

J. Amortization of Hardship Protected Accounts

1. Introduction

Hardship protected accounts are residential accounts that are protected from shut-off by the utility for nonpayment. 220 C.M.R. §§ 25.03, 25.05. To qualify for protected status from service termination, customers must demonstrate that they have a financial hardship and meet certain other requirements, such as a household member suffering from a serious illness or residing with a child under twelve months of age. See 220 C.M.R. §§ 25.03(1), 25.03(3), 25.05(3).[168] All qualified accounts are protected from shut-off for nonpayment year round,

[168] An account qualifies for protected status where the customer certifies that the customer has a financial hardship, and: (1) a person residing in the household is seriously ill; (2) a child under the age of twelve months resides in the household; (3) the customer takes heating service between the period November 15th and March 15th, and the service has not been shut off for nonpayment prior to November 15th; or (4) all adults residing in the

except for heating customers with a financial hardship. These heating accounts are protected from shut-off for nonpayment only during the winter moratorium period, November 15th through March 15th. 220 C.M.R. §§ 25.03(1)(a)3, 25.03(1)(b).

The Company states that because hardship protected accounts cannot be disconnected, the accounts remain active and continue to receive service despite slow or non-payment of amounts due (Exh. NG-RRP-1, at 49). Further, the Company notes that if an active hardship protected customer's account balance is in arrears, the Company is prohibited by the Department's regulations from collecting the overdue balance (Exh. NG-RRP-1, at 51). As a result, the active hardship protected customer accounts receivable balances in arrears increase over time (Exh. NG-RRP-1, at 51).

According to the Company, its hardship protected account receivable balance over 360 days[169] was $40,607,637 as of June 30, 2015, the end of the test year (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 24). The Company updated its active hardship protected balance over 360 days throughout the proceedings and reported a balance of $52,027,414, as of July 30, 2016 (Exh. WP-NG-RRP-13 (Rev. 3)). The Company proposes to recover the $52,027,414 over a five-year period, which results in an annual amortization expense of $10,405,483 (Exhs. NG-RRP-2, at 24 (Rev. 3); NG-RRP-8, at 2).

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household are age 65 or older and a minor resides in the household. 220 C.M.R. § 25.03. Customers who are unable to pay an overdue bill and meet the income eligibility requirements for the Federal Low-Income Home Energy Assistance Program are deemed to have a financial hardship. 220 C.M.R. § 25.01(2).

169 That is, hardship protected account receivables overdue for payment more than 360 days.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject National Grid's proposal to recover its hardship account receivable balance over 360 days because: (1) approving the recovery of these balances at this point would effectively write-off the accounts as bad debt before such determination can be made; and (2) eventually the Company will recover these balances either from the hardship customers themselves when they pay their bills or from the other customers through the bad debt expense and cash working capital allowance included in the cost of service (Attorney General Brief at 56). Further, the Attorney General contends that if the Company recovers these balances through rates, it will have no incentive to seek recovery of the balances from delinquent customers (Attorney General Brief at 56).

Alternatively, the Attorney General argues that if the Department approves the recovery of National Grid's hardship account receivables balance, the Department also should adjust the Company's cash working capital allowance to reflect the fact that the balances no longer will affect the revenue lag associated with its cash working capital requirement (Attorney General Brief at 57-58; Attorney General Reply Brief at 33). This alternative argument was addressed in Section VII.C.2.a above.

b. Company

The Company argues that the Department should reject the Attorney General's recommendations and instead approve the recovery of the hardship account receivable balance with no corresponding adjustment to its cash working capital allowance (Company Brief at 57-59; Company Reply Brief at 44-46). In particular, the Company contends that its proposal is consistent with Department precedent, as it is limited to balances that are in arrears over 360 days and unlikely to be repaid by the account holders (Company Brief at 57-58; Company Reply Brief at 45). According to National Grid, unless its proposal is approved, the Company will be unable to recover the balances as bad debt until the account holders' protected status expires (Company Brief at 58; Company Reply Brief at 45). National Grid maintains that during this time the arrearages will continue to grow and add to the burden of all customers who eventually will be required to bear the costs through the Company's uncollectible expense (Company Brief at 58; Company Reply Brief at 45). Further, the Company rejects the notion that approval of its proposal would provide a disincentive for it to continue collection methods against delinquent customers (Company Brief at 58, citing Tr. 8, at 1375-1377; Company Reply Brief at 45).

Finally, National Grid argues that if its proposal is approved, the Department should not adjust the Company's cash working capital allowance (Company Brief at 58-59; Company Reply Brief at 45-46). This argument was addressed in Section VII.C.2.b above.

3. Analysis and Findings

Under current ratemaking practice, there is no cost of service mechanism for the Company to recover the balance of protected hardship accounts receivable. See D.P.U. 10-70, at 210-211, n.12. Public policy decisions and economic conditions persuade us to consider whether and how to treat these costs. D.P.U. 10-70, at 214. Unlike expenses that may be deferred for recovery in a subsequent rate case, the balance of protected hardship accounts receivable cannot be recovered in rates unless the asset is deemed impaired and written off. D.P.U. 10-70, at 210-211, n.12. However, because a utility's hardship protected accounts remain active, the utility cannot write off the unpaid balance, and therefore, cannot recover the amounts as bad debt expense on a timely basis. D.P.U. 15-80/D.P.U. 15-81, at 169; D.P.U. 13-90, at 159; D.P.U. 10-70, at 213. Generally accepted accounting principles require that, without probable recovery of outstanding balances, a company must recognize an impairment loss through a charge to its income statement and establish a reserve account on its balance sheet for the impaired asset. D.P.U. 10-70, at 214-215.[170]

To provide for the probability of recovery and to avoid an impairment loss, the Department has permitted utilities to collect through distribution rates an amortized amount of significant protected hardship account receivables balances that are over 360 days past due. D.P.U. 15-80\D.P.U. 15-81, at 171; D.P.U. 14-150, at 236; D.P.U. 13-90, at 166; D.P.U. 10-70, at 219. The Company's protected hardship account receivables balance is in line with the levels experienced by Western Massachusetts Electric Company and Fitchburg Gas and Electric Light Company (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 3, 24 (Rev. 3)). D.P.U. 13-90, at 165 & n.110; D.P.U. 10-70, at 216 n.115, 219. Therefore, for purposes of determining ratemaking treatment for National Grid's active protected hardship account receivables, we find that its test year end balances are significant.

By allowing recovery in these circumstances, the Department seeks to provide for the probability of recovery of these older outstanding balances. In light of the record in this case, we see no reason to depart from this ratemaking treatment (Exh. NG-RRP-1, at 51-53). Based on these considerations, the Department allows National Grid to recover its test year balance of

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170 See Statement of Financial Accounting Standards No. 144.

protected hardship account receivables in the amount of $40,607,637.[171] Accordingly, we deny the Company's proposal to recover $52,027,414.[172]

As noted above, the Company has proposed to amortize recovery of the balance over five years (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 24). Amortization periods are determined based on a case-by-case review of the evidence and underlying evidence. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 99 (2009); D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. In this case, we consider the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period. Amortizing the amount of $40,607,637 over five years produces an annual expense of $8,121,527 (Exhs. NG-RRP-1, at 36, 50; NG-RRP-2, at 24). Accordingly, we reduce the Company's proposed cost of service by $2,283,956 ($10,405,483 - $8,121,527).

As noted above, the Company sought to update the protected hardship account receivables balance throughout the course of this proceeding, and after the evidentiary hearings concluded (Exhs. NG-RRP-2, at 24 (Rev. 2), (Rev. 3)). However, the Department typically accepts post-hearing updates related to only a limited set of issues – most notably, updated

171 Recovery through amortization of protected account receivables balances greater than 360 days past due, which amounts to $40,607,637 as of June 30, 2015, balances the financial considerations of the Company and the bill impacts to ratepayers without hardship protected status. D.P.U. 10-70, at 219.

172 The Department acknowledges that in the recent NSTAR Gas Company base rate case, we approved the recovery of some post-test year protected hardship receivables account balances over 360 days. D.P.U. 14-150, at 236. In that case, however, the record did not provide the test year balance. We find that there was no express intention on the Department's part to change its precedent.

property tax bills and updated rate case expense totals. See, e.g., D.P.U. 93-223-B at 15; Hutchinson Water Company, D.P.U. 85-194-B at 4 (1986); Western Massachusetts Electric Company, D.P.U. 84-25-A, at 10 (1984). The Department does not find it appropriate to extend its post-hearing update practice to include updated protected hardship account receivable balances. Instead, we find that permitting recovery of the test year amount of receivables provides a measure of assurance of recovery of the older outstanding balances.

In addition, we direct the Company to track the accounts included in the balance of hardship protected receivables accounts allowed for recovery so that the associated costs are excluded from recovery through normal bad debt expense. D.P.U. 10-70, at 220. The Company shall credit through the Residential Assistance Adjustment Factor ("RAAF") any subsequent payments made by customers towards balances that the Company has amortized (Exh. NG-RRP-1, at 52). D.P.U. 10-70, at 221. In this regard, the Company shall modify its Residential Assistance Adjustment Provision accordingly. Finally, we direct each distribution company with hardship protected account receivable balances approved for recovery by the Department to provide as part of the initial filing in the company's next base rate case, the following information: (1) a detailed narrative of the company's collection efforts relative to outstanding hardship account balances recovered through amortization since the prior base rate case; and (2) the annual amount of payments made by customers against these hardship account balances since the prior rate case.

K. Amortization of ASC 740 Regulatory Asset

1. Introduction

On July 24, 2013, the Legislature passed An Act Relative to Transportation Finance, St. 2013, c. 46 ("Transportation Finance Bill"). In pertinent part, the Transportation Finance Bill repealed G.L. c. 63, § 52A, which provided for a state franchise tax rate of 6.5 percent for public utility corporations (see Exh. NG-RRP-1, at 46). See also St. 2013, c. 46, § 39. Consequently, utility corporations lost their separate tax status for tax years beginning on and after January 1, 2014, and became subject to the tax rates applicable to corporations pursuant to G.L. c. 63, § 39. (Exhs. NG-RRP-1, at 46; AG-2-36; Tr. 6, at 956). For National Grid, the tax rate increased from 6.5 percent to 8.0 percent (Exh. NG-RRP-1, at 46; AG-2-36; Tr. 6, at 956).

National Grid states that the increase in the franchise tax rate created an accumulated deferred income taxes deficiency on the Company's books (Exh. NG-RRP-1, at 46; Tr. 6, at 954-957). As a result, pursuant to Accounting Standards Codification 740 ("ASC 740") (formerly Statement of Financial Accounting Standard No. 109 ("FAS 109")), National Grid recorded an additional $11,907,760 in accumulated deferred income tax liability ($11,717,222 for MECo and $190,537 for Nantucket Electric) (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); DPU-34-6; AG-2-36, Att. 1). The Company proposes to recover the $11,907,760 over a five-year period, which results in an annual deferred income tax amortization expense of $2,381,552 (Exhs. NG-RRP-2, at 32 (Rev. 3); DPU-34-6).

At the same time, the Company proposes to offset the accumulated deferred income tax deficiency with a cumulative deferred tax liability of $14,111,602 associated with a tax basis balance sheet true-up for MECo that also will be amortized over a five year period, which results in a reduction of $2,822,320 in annual amortization expense (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); AG-2-36-2; Tr. 6, at 957-958). Together, these two adjustments result in a net amortization amount of negative $440,768 ($2,381,552 - $2,822,320), which the Company proposes to record as a reduction to income tax expense (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); NG-RRP-8, at 8 (Rev. 3); Tr. 6, at 961).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that because the majority of the increase in deferred tax liability was property related, the increase in the deferred tax liability was not payable immediately, and will not be payable over the next five years (Attorney General Brief at 28, citing Exh. AG-DJE-4). Instead, the Attorney General contends that the tax liability will be paid back over the remaining life of the Company's property as that property depreciates (Attorney General Brief at 29). Therefore, the Attorney General asserts that the Company's proposed five-year amortization period is inappropriate because the Company would then recover the increased income taxes more rapidly than they are actually being paid (Attorney General Brief at 29).

The Attorney General argues that consistent with Department precedent, the appropriate amortization period for the plant-related ASC 740 regulatory assets is the estimated remaining service lives of the Company's plant assets (Attorney General Brief at 29, citing D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n. 136; D.P.U. 92-111, at 172-173; Attorney General Reply

Brief at 13-14).[173] The Attorney General points out that the Department recently reaffirmed that it was appropriate to recover deferred tax regulatory assets "over an amortization period reflective of the remaining life of the company's utility plant in service at the time" (Attorney General Brief at 29, citing D.P.U. 14-150, at 241). In addition, the Attorney General argues that the Company has provided no compelling reasons to depart from this precedent for plant-related items (Attorney General Reply Brief at 14).

The Attorney General argues that of the $11,907,760 in increased corporate excise tax, $10,077,661 is plant related and subject to an amortization period based on the remaining life of the Company's net plant in service (Attorney General Brief at 28-29, citing Exh. AG-DJE-1, at 13; Attorney General Reply Brief at 13-14). In this regard, the Attorney General argues that the Company's schedules show that the average remaining life of the Company's net plant in service as of the end of the test year is 18 years (Attorney General Brief at 29, citing Exh. NG-RRP-2, at 27). She states that amortizing the plant-related portion of the ASC 740 regulatory assets over 18 years reduces the Company's annual amortization to $559,870, which is $1,455,662 less than proposed by the Company (Attorney General Brief at 29, citing Exh. AG-DJE-1, Sch. DJE-4). Alternatively, the Attorney General notes that her own analysis of National Grid's average service lives and depreciation accrual rates show that the remaining life of the Company's net plant in service is 21 years, which would reduce the annual amortization of the plant-related portion of the regulatory asset to $479,889 ($10,077,661 ÷ 21) (Attorney General Brief at 30).

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173 The Attorney General accepts the Company's proposed five-year amortization of non-plant related ASC 740 regulatory assets (Attorney General Reply Brief at 13-14).

Regarding the Company's proposed five-year amortization period of MECo's excess deferred income tax balance of $14,111,602, the Attorney General does not contest the Company's proposal (Attorney General Reply Brief at 14).

b. Company

The Company concedes in making its proposal that it was mindful of the Department's recent precedent relating to the amortization period of regulatory assets (Company Brief at 52, citing D.P.U. 14-150; D.P.U. 13-75). However, the Company argues that its proposal is intended to return to ratepayers the deferred tax balance sheet true-up over an accelerated period as opposed to returning the net credit to customers over a longer period as proposed by the Attorney General (Company Brief at 52, citing Tr. 6, at 959-960; Tr. 9, at 1482-1483). Therefore, the Company urges the Department to reject the Attorney General's proposed amortization period (Company Brief at 53).

3. Analysis and Findings

ASC 740 requires companies to recognize on their financial statements all previously unrecorded future income tax liabilities (see Exh. NG-RRP-1, at 46). See also D.P.U. 13-75, at 269; D.T.E. 05-27, at 227. The change in National Grid's state income tax expense arising from the enactment of the Transportation Finance Bill results in deficiencies in the Company's deferred state income tax reserve (Exhs. NG-RRP-1, at 46; AG-2-36). The Department has reviewed the Company's proposal and finds that National Grid may recover a regulatory asset of $11,907,760 as a result of the increase in the franchise tax rate (Exh. NG-RRP-2, at 32 (Rev. 3)).

As noted above, the Company claims that its proposed amortization period of five years is intended to return to ratepayers the deferred tax balance sheet true-up over an accelerated period as opposed to returning the net credit to customers over a longer period as proposed by the Attorney General (Company Brief at 52, citing Tr. 6, at 959-960; Tr. 9, at 1482-1483). Notwithstanding the Company's argument, however, in the case of a deficiency in a deferred income tax reserve, such as that associated with the change in state income rate as a result of the Transportation Finance Bill, a longer recovery period serves to reduce the annual amortization, thus benefiting customers. More significantly, the Department has found that it is appropriate to recover ASC 740 regulatory assets over an amortization period reflective of the remaining life of the company's utility plant in service at the time, pursuant to the South Georgia method.[174] See, e.g., D.P.U. 14-150, at 241; D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n.136; D.P.U. 95-40, at 50; D.P.U. 92-111, at 172-173; Essex County Gas Company, D.P.U. 87-59, at 55-56 (1987). The Company has provided no compelling reasons to depart from this precedent for plant-related items.

Approximately 15 percent of the Company's accumulated deferred income taxes deficiency, however, is due to non-plant related book tax timing differences, which can be subject to a quicker turnaround than most plant items (Exh. DPU-34-6). The Department finds that it is appropriate to consider the shorter turnaround associated with non-plant related timing differences in determining the appropriate amortization period in this instance. D.P.U. 14-150, at 241-242.

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174 Pursuant to the South Georgia method, accumulated deferred income tax deficiencies resulting from changes in tax rates are recovered on a straight-line basis, by amortizing the deficiency over the remaining regulatory life of the property. D.P.U. 14-150, at 241 n.145. This approach is referred to as the "South Georgia" method because it was first prescribed by the Federal Power Commission in South Georgia Natural Gas Company, FPC RP-77-32. D.P.U. 92-111, at 171 n.49; D.P.U. 87-59, at 55-56.

National Grid's net plant balance as of October 1, 2016 (proximate to the date of this Order) is calculated at $2,307,263,848 (Exh. NG-RRP-2, at 30 (Rev. 3)). Application of the depreciation accrual rates approved in this Order to the respective plant investment account balances produces a depreciation expense of $125,244,314 (see Exh. NG-RRP-2, at 27 (Rev. 3); Section VIII.E.5.e above). Accordingly, we find that the remaining life of the Company's plant is 18.4 years.[175] The Department will calculate a five-year amortization period for the 15 percent of non-plant-related accumulated deferred income taxes, and an 18.4-year amortization period to the 85 percent of plant-related accumulated deferred income taxes, resulting in a total annual amortization period of 16.39 years.[176] Thus, the Department finds that the appropriate amortization period for the Company's ASC 740 regulatory asset is 16 years. Based on the foregoing, the Department approves the Company's recovery of its regulatory asset of $11,907,760 over a period of 16 years. Application of this amortization period to the approved balance produces an annual amortization of $744,235.

Regarding the Company's excess deferred income taxes resulting from MECO's balance sheet true-up, the Department has examined the Company's calculations (Exh. AG-2-36, Att. 2). Based on this review, we find that the Company has properly calculated the excess deferred taxes of $14,111,602. The Department also finds that five years represents a reasonable amortization period applicable to the deferred tax balance sheet true-up. Application of this amortization period to the approved balance produces an annual amortization of negative $2,822,320.

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175 The $2,307,263,848 net plant balance divided by a depreciation expense of $125,244,314 results in a remaining life equal to 18.4 years.

176 (18.4 years x 0.85) + (5.0 years x 0.15) = 16.39 years.

The net effect of these two amortizations is a net unfunded deferred tax liability of negative $2,078,085. National Grid has included an amortization amount of negative $440,768 in its income tax calculation (Exh. NG-RRP-2, at 31 (Rev. 3)). Accordingly, the Department will reduce National Grid's proposed income tax adjustment by $1,637,317. The effect of this adjustment on the Company's income tax expense is presented in Schedule 8 of this Order.

L. FAS 112 Expense

1. Introduction

FAS 112[177] establishes standards of financial accounting and reporting for the estimated cost of benefits provided by an employer to former or inactive employees after employment but before retirement ("postemployment benefits") (see Exhs. NG-RRP-Rebuttal-1, at 31; DPU-30-3; FAS 112: Employers' Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43, at 4, found at: http://www.fasb.org/jsp/FASB/Document_C/DocumentPage?cid=1218220123881&acceptedDisclaimer=true ("FAS 112")). Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents (FAS 112, at 4-5).[178] This group includes employees who have been laid off and those on disability leave, regardless of whether they are expected to return to active status (FAS 112, at 5). National Grid states that

177 In 2009, as part of a general recodification of the Financial Accounting Standards Board's accounting rulings, FAS 112 became part of ASC 712 (see Exh. NG-RRP-Rebuttal-1, at 31).

178 More specifically, postemployment benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage (FAS 112, at 5).

because these expenses are volatile and impacted by the actuarial assumptions used to arrive at the annual expense accrual, the Company normalizes the costs based on an historical average level (Exh. NG-RRP-1, at 22).

During the test year, National Grid booked a negative $2,258,474 in FAS 112 expense (Exh. NG-RRP-2, at 14).[179] However, the Company books annual FAS 112 expenses based on a five-year average expense (Exhs. NG-RRP-1, at 22; NG-RRP-2, at 14; NG-RRP-Rebuttal-1, at 31). In its initial filing, National Grid reported that the most recent five-year average expense charged to O&M was $495,065, which comprised the period commencing with the Company's fiscal year ended March 31, 2011 through its fiscal year ended March 31, 2015 (Exhs. NG-RRP-1, at 22; NG-RRP-2, at 14; NG-RRP-Rebuttal-1, at 31). As such, the Company proposed a normalizing adjustment of $2,753,539 (Exh. NG-RRP-2, at 14). As discussed further below, in response to issues raised by the Attorney General, the Company revised its five-year average FAS 112 expense to $78,733 (Exhs. NG-RRP-2, at 14 (Rev. 3); WP-NG-RRP-7 (Rev. 1)). This revised total represents a reduction of $416,331 from the $495,065 five-year average FAS 112 expense charged to O&M in the initial filing (Exh. NG-RRP-2, at 14 (Rev. 3)). Because its test year FAS 112 expense was a negative $2,258,474, the Company now proposes a revised normalization adjustment of $2,337,208 (Exh. NG-RRP-2, at 14 (Rev. 3)).

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179 The Company attributes the negative FAS 112 expense to significant gains realized as a result of an increase in the discount rate, favorable claims experience, and a reduction in long-term disability income replacement claimants (Exh. DPU-30-6).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company should revise its FAS 112 expense in two ways: (1) update the average expense to include fiscal year 2016 expense; and (2) use a four-year expense average instead of a five-year average (Attorney General Brief at 36-38). Regarding the first revision, the Attorney General notes that including fiscal year 2016 expense in the FAS 112 calculation would capture a portion of the Company's test year expense (Attorney General Brief at 36). She points out that the Company agrees to this revision (Attorney General Brief at 36).

Regarding the second revision, the Attorney General argues that it is appropriate to exclude from the FAS 112 calculation the expense associated with fiscal year ended 2012 because the Company's external actuarial firm revised the method used in determining the FAS 112 expense beginning with the fiscal year ended March 2013 (Attorney General Brief at 37, citing Exhs. NG-RRP-7, at 12, 51; AG-DR-1, at 19). The Attorney General contends that the use of fiscal years prior to the change in methodology would produce results that are inconsistent with the current method used by the actuarial firm (Attorney General Brief at 37). Thus, she asserts that the normalized FAS 112 expense should be based on the most recent four-years of actuarially determined expense levels instead of a five-year average in order to exclude the effects of the prior method and allow for a more consistent comparison of expense levels (Attorney General Brief at 37-38, citing Exh. AG-DR-Rebuttal at 10).

According to the Attorney General, normalizing the FAS 112 expense based on the most recent four years of actuarial evaluations results in a FAS 112 expense of a negative $427,748

(Attorney General Brief at 38, citing Exhs. AG-DR-1, at 20: AG-DR-2, Sch. 5). The Attorney General asserts that, while this approach would result in a negative amount of FAS 112 expense in rates, the expense is representative of the Company's recent experience (Attorney General Brief at 38).

b. Company

The Company agrees that its FAS 112 expense should be revised to include the most recent financial information associated with fiscal year 2016 (Company Brief at 46, citing Exhs. NG-RRP-Rebuttal-1, at 32; NG-RRP-Rebuttal-5). However, the Company disagrees with the Attorney General's recommendation to exclude fiscal year 2012 FAS 112 expense data and to normalize the FAS 112 expense based on the most recent four years of actuarially determined expense levels (Company Brief at 46-49). In particular, the Company contends that the Attorney General misunderstands the impact of the change in method used to calculate the FAS 112 (Company Brief at 47-48). The Company notes that the changes in the method used to calculate FAS 112 expense only have the effect of increasing FAS 112 costs, and maintains that had these changes been incorporated in the fiscal year 2012 valuations, then the cost for that year could only be higher (Company Brief at 47-48, citing Exh. NG-RRP-Rebuttal-1, at 33). Further, according to the Company, adopting the Attorney General's recommendation would result in the inclusion of a negative FAS 112 expense in rates, and thus inappropriately would presume that the Company is earning revenues from its FAS 112 obligations that get passed back to customers (Company Brief at 49). The Company argues that, while FAS 112 expense can be negative from time to time, it is normally a positive expense (Company Brief at 49).

Instead, the Company maintains that the FAS 112 expense should be based on the most recent five years of actuarial data for fiscal years 2012 through 2016, which would result in a five-year average FAS 112 expense of $78,733 (Company Brief at 46, citing Exh. WP-NG-RRP-7 (Rev. 1)). The Company notes that this revised total represents a reduction of $416,331 from the $495,065 five-year average FAS 112 expense charged to O&M in the initial filing (Company Brief at 46, citing Exhs. NG-RRP-7 (Rev. 1); NG-RRP-2, at 14 (Rev. 2)). The Company asserts that because its test year FAS 112 expense was a negative $2,258,474, a revised normalization adjustment of $2,337,208 is appropriate (Company Brief at 46).

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 expense level (Exhs. NG-RRP-1, at 22; DPU-30-5). These assumptions include the discount rate, mortality, termination rates, disablement rates for active employees, cost of medical coverage, and health care cost trend rates (Exh. DPU-30-4). Consequently, it is reasonable to normalize FAS 112 costs based on an historical average level. See, e.g., D.P.U. 09-39, at 146-149.

In evaluating the Company's proposed adjustment to its FAS 112 expense, we find that it is appropriate for the Company to include in the calculation actuarial data from the most recent fiscal year (i.e., 2016). Further, we are not persuaded by the Attorney General's arguments that it is necessary to revert to a four-year average expense by excluding fiscal year 2012. The Attorney General focuses on the following changes in the method used by the Company's external actuarial firm in determining the FAS 112 expense:

> A change in the accrual method for those groups with benefits that accumulate over a given period (i.e., those with benefits that vary based on a specific age/service criteria). Previously, liabilities for future disableds beyond the current fiscal year were not considered in the valuation for these groups. Our valuation now includes a liability for the expected future disableds for benefits that accumulate over the specific age/service period.
>
> A discount rate assumption that is specific to the shorter duration of the [FAS 112] obligations rather than using the same discount rate used for the company's pension and postretirement medical/life insurance plans.

(Exh. NG-RRP-7, at 12).

While we acknowledge the Attorney General's concerns regarding the change in the way FAS 112 expenses are calculated, we find that the change in accounting for future disabled employees and the use of a lower discount rate would generate a higher liability, and consequently result in higher FAS 112 costs (Exh. NG-RRP-Rebuttal-1, at 33-34). Thus, the exclusion of fiscal year 2012 FAS 112 expenses would skew the overall calculation and produce an average expense that is not representative of the Company's actual FAS 112-related activity.

We conclude 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. The five-year average expense charged to O&M during this period was $78,733 (Exhs. NG-RRP-2, at 14 (Rev. 3); WP-NG-RRP-7, at 1 (Rev. 1)). As noted above, the Company's test year FAS 112 expense was a negative $2,258,474 (Exh. NG-RRP-2, at 14 (Rev. 3)). Accordingly, we accept the Company's revised normalization adjustment of $2,337,208.

M. Corporate Aircraft Expense

1. Introduction

NGSC provides aviation operations support to its affiliates through its ownership of a 1999 Beechcraft Model 1900D aircraft ("airplane") (Exhs. AG-1-54; AG-1-92, Att. 1, at 15).[180] The Company is allocated a portion of the total expenses associated with the airplane, based on a general allocator consisting of equally weighted ratios of net plant, net margin, and net O&M expenses (Exh. AG-22-10, Att.).[181] During the test year, National Grid was allocated $254,348 in O&M expenses relative to the airplane and its hangar facility located in Syracuse, New York, $82,079 in depreciation expense for the airplane,[182] and $51,060 in airport property taxes, for a total expense of $387,487 (Exhs. AG-22-10; AG-25-19, Att.; AG-25-20, Att.). The Company proposes to decrease its test year cost of service by $7,138 to reconcile the difference between the booked depreciation expense of $82,079, and the calculated depreciation expense of $74,941, based on the allocation factors in use during the test year (Exhs. NG-RRP-2, at 5 (Rev. 3); AG-1-29, Att. at 1; AG-22-10; AG-25-20).

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180 NGSC also owns a 1985 Bell 206L-3 helicopter and a 2014 Bell 429 helicopter (Exh. AG-1-54). Because these helicopters are used exclusively in support of National Grid USA's non-Massachusetts jurisdictional companies, the Company is not allocated any of their associated costs (Exh. AG-25-20).

181 MECo and Nantucket Electric were allocated a combined 18.37 percent of the total airplane-related expenses during the last half of 2014, and a combined 19.04 percent during the first half of 2015 (Exh. AG-22-10, Att.).

182 The Company records depreciation on assets held by the service company as rent expense (Exhs. AG-1-29, Att.; AG-1-92; AG-25-20).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has failed to justify either the need for or the expenses associated with its airplane (Attorney General Brief at 60). She notes that the Department has previously excluded from a utility's cost of service expenses associated with aircraft and other vehicles that were found to be unreasonable (Attorney General Brief at 60, citing D.P.U. 13-75, at 225-226; Fall River Gas Company, D.P.U. 750, at 15 (1982); D.P.U. 18571/18572, at 12-13). The Attorney General recommends that the Department eliminate all test year costs relative to the airplane, and reduce the Company's test year cost of service by $387,486 (Attorney General Brief at 60).[183]

b. Company

National Grid defends its inclusion of airplane-related expenses in its proposed cost of service.[184] The Company notes that National Grid USA has operating companies in Massachusetts, New York, and Rhode Island, as well as a centralized service company providing services to these operating companies (Company Brief at 67-68). In this regard, National Grid maintains that employees providing service to multiple companies must travel to the various states for work-related reasons,[185] and that such out-of-state travel that directly or indirectly

183 The difference between the Attorney General's proposed reduction and National Grid's test year expense is due to rounding.

184 The Company emphasizes that costs related to the two helicopters have been excluded from the proposed revenue requirement (Company Brief at 67, citing Exhs. AG-1-54; AG-22-10).

185 For example, the Company notes that three of its witnesses in this proceeding are New York-based NGSC employees who had to travel to Massachusetts in order to perform

affects Company operations is undertaken for the benefit of ratepayers and, therefore, is a reasonable expense (Company Brief at 67-68, citing D.P.U. 13-75, at 225).

Further, the Company contends that the Department has recognized that the use of corporate aircraft provides a cost-effective means of traveling for entities that have operating companies in multiple jurisdictions, and that it is reasonable and appropriate to allocate some aircraft expenses to an operating company (Company Brief at 68, citing D.P.U. 13-75, at 225 (2014); D.P.U. 12-25, at 263; D.T.E. 05-27, at 232).[186] Consequently, National Grid concludes that the Department should reject the Attorney General's recommendation and include the full amount of the airplane costs in the Company's cost of service (Company Brief at 68).

3. Analysis and Findings

The Department recognizes that out-of-state travel for business meetings that directly or indirectly affect a utility's operations can be considered to have been made for the benefit of the Company's customers, and thus reasonable expenses associated with such travel are allowable for ratemaking purposes. D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; D.T.E. 05-27, at 233; D.P.U. 92-111, at 154. Further, the Department has found that the use of lease and charter jets provide a cost-effective means of travelling throughout a utility's multi-state operating territory. D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; D.T.E. 05-27, at 232. However, the Department has

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their duties relative to this proceeding (Company Brief at 68, citing Exhs. NG-MPH-1, at 1; NG-DJD-Rebuttal-1, at 1).

186 National Grid analogizes the allocation to the Company of certain aircraft expenses to the allocation of a portion of NiSource Corporate Service Company's airplane costs to Bay State Gas Company which were previously reviewed and approved by the Department in D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; and D.T.E. 05-27, at 232 (Company Brief at 68).

excluded from cost of service vehicles and vehicle-related expenses when use of those vehicles was found to be unreasonable. D.P.U. 750, at 15; D.P.U. 18571/18572, at 12-13.

In the instant case, National Grid shares in the costs associated with the airplane, which is used by employees conducting Company-related business (Exh. AG-1-54). Therefore, it is reasonable to allocate some of the airplane expenses to the Company.

The Department has examined both the airplane-related billings and the allocation formulas used to allocate airplane costs to the Company (Exhs. AG-1-92; AG-22-10; AG-25-20). Although other ways could be devised to allocate the airplane costs among National Grid USA's affiliates, the existence of other possible allocation outcomes does not render the Company's allocation method invalid. D.T.E. 03-40, at 204; Commonwealth Electric Company, D.P.U. 88-135/151, at 83 (1989). Based on our review, the Department finds that the method used to allocate the airplane expenses to National Grid is reasonable, is provided at cost, and produces both cost-effective and nondiscriminatory results for the use of the airplane by the Company.

N. NGSC Allocations

1. Introduction

NGSC provides services to National Grid in thirteen functional areas: audit, corporate affairs, customer, finance, human resources, information systems, legal, network strategy, operations, procurement, regulation and pricing, shared services, and strategy, business development and technology (Exh. DPU-25-18, Att.).[187] The Company incurs expenses from

[187] Some employees that provide services to National Grid affiliates are categorized as "other affiliate employees," but these employees provide services to National Grid affiliates akin to service company employees (Exh. DPU-28-7). For example, employees

NGSC in two ways: (1) through direct charges, which are billed to National Grid for costs incurred by NGSC employees directly related to the Company; and (2) through common costs, which are allocated among the affiliates that receive the services provided by NGSC, based on allocation factors and billing pools (Exh. NG-RRP-1, at 12). National Grid included in the test year NGSC charges in their respective expense categories included in the cost of service (e.g., salary and wages) (Exhs. NG-RRP-1, at 12; NG-RRP-2, at 6, 9 (Rev. 3)). Additionally, the Company included NGSC charges in the normalizing or known and measurable adjustments to the cost of service in their respective expense categories (e.g., the proposed adjustment of $3,456,591 to salary and wage expense for service company employees is included in the total proposed $8,966,172 adjustment to salary and wage expense) (Exhs. NG-RRP-1, at 12; NG-RRP-2, at 6, 9 (Rev. 3)). In the test year, the Company incurred $201,513,353 of O&M expenses originating from NGSC (Exh. DPU-4-4, Att.). National Grid proposes $15,437,187 in pro forma adjustments to NGSC-related test year expenses (Exh. DPU-4-7).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that there is little management accountability regarding service company costs, including control of the costs, and the effect of those costs on customers

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in National Grid's US Services Delivery Center ("SDC"), which supports human resources, procurement, customer, and finance processes, are employees of Niagara Mohawk Power Corporation ("Niagara Mohawk"), but allocate their time to other National Grid affiliates, including the Company, based on services the SDC employees provide to the various affiliates (Exh. DPU-28-7; RR-DPU-3). The SDC employees are primarily unionized workers, and their collective bargaining agreement is between their union and Niagara Mohawk (RR-DPU-3). Therefore, although these employees are not categorized as service company employees, their work time and associated costs are allocated in a similar manner as service company employees (Exhs. DPU-12-12; DPU-28-7; RR-DPU-3).

(Attorney General Brief at 2, citing RR-AG-1, Att.). According to the Attorney General's calculations, NGSC charges to the Company grew 71.26 percent, or 9.38 percent per year on average, from 2008 to 2014 (Attorney General Brief at 2, citing Exh. AG-KC-1, at 4). The Attorney General contends that this growth in costs is greater than the rate of inflation and the average growth rate of the median household income in Massachusetts over the same period (Attorney General Brief at 2, citing Exh. AG-KC-1, at 4-5). Further, the Attorney General claims that the increasing service company costs partially explain the increase in the Company's proposed cost of service (Attorney General Brief at 2). As a result, the Attorney General asserts that the Department should limit the costs allowed to be recovered from customers in this case[188] (Attorney General Brief at 3).

b. Company

National Grid argues that the NGSC charges are reasonable and properly allocated to the Company (Company Brief at 91). Therefore, National Grid recommends that the Department approve the NGSC charges included in the Company's cost of service (Company Brief at 91-92).

3. Analysis and Findings

a. Introduction

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and

188 The Attorney General suggests that one solution is modifying National Grid's rate recovery mechanisms to incentivize the Company to minimize costs (Attorney General Brief at 3). The Attorney General claims that the Company's current reconciling rate mechanisms provide a perverse incentive for the Company to earn more as spending increases (Attorney General Brief at 3). The Department addresses National Grid's rate recovery mechanisms in Sections V and VI.

(3) allocated to the utility by a method that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 13-75, at 184; D.P.U. 12-25, at 231; D.P.U. 89-114/90-331/91-80 (Phase I) at 79-80; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). In addition, 220 C.M.R. § 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.

b. Services

In determining whether the services rendered by an affiliate specifically benefit a regulated utility and do not duplicate services already provided by the utility, it is necessary to examine whether there is any overlap between the services rendered by an affiliate and the operating company's functions. D.P.U. 13-75, at 184; D.P.U. 08-27, at 80-81; Oxford Water Company, D.P.U. 1699, at 11-12 (1984). Within the 13 functional groups, services provided by NGSC to the Company include: accounting, payroll, auditing, finance/business planning, business continuity and emergency response, communications, human resources, engineering, transmission construction, corporate and corporate records, risk management, and management, environmental, insurance, tax, legal, treasury, regulatory, energy efficiency services, facilities, information technology, customer relations, and other various functions (Exh. DPU-1-25, at 1-2; see Exh. DPU-25-18, Att.). The Company does not have employees who perform these tasks

(Exh. DPU-1-25, at 2). Therefore, these activities specifically benefit National Grid, and there is no overlap between the services rendered by NGSC and the Company's functions.

c. Price

Next, we evaluate whether NGSC charges to National Grid were at a competitive and reasonable price. In prior cases, when determining whether services were charged at a competitive and reasonable price, the Department has accepted a review of employer compensation structures, compared to the market, because service company charges tend to be primarily labor-related.[189] D.P.U. 13-75, at 186; D.P.U. 12-25, at 233; D.P.U. 09-39, at 260. Regarding a review of National Grid's compensation structures, the Company's proposal shows that it established a salary range for each band of non-union employees that is competitive with the median market rate (Exhs. NG-MPH-1, at 12; NG-MPH-1; DPU-8-24). Moreover, NGSC labor is charged to the Company at cost and does not include a profit that would be charged by an outside vendor (Exhs. DPU-1-25, at 2; DPU-25-13, at 1).

In addition to comparing service company compensation to that of the market, National Grid provided additional evidence of the competitiveness and reasonableness of NGSC costs. In particular, the Company developed external cost comparisons to demonstrate that NGSC costs are reasonable relative to the corresponding market alternatives (Exh. DPU-25-13, at 2). For two-thirds of service company functions, external cost comparisons show that the services provided by NGSC compare favorably to third-party rates obtained through the market

189 The Company acknowledges that the primary costs (i.e., more than 50 percent of total costs) allocated to the Company from NGSC are labor and labor-related costs associated with employees performing the functions that are provided on a shared basis (Exh. DPU-1-25, at 2). NGSC allocated or directly charged $73,393,666 in test year salary and wages to the Company (Exh. NG-RRP-2, at 9 (Rev. 3)).

(Exhs. DPU-25-13, at 2; DPU-25-19, Att. & Att. (Supp.)).[190] National Grid's analysis also shows that the vast majority of services performed by NGSC for the Company are provided at a lower cost than an outside vendor (Exhs. DPU-25-13, at 2; DPU-25-19, Att. & Att. (Supp.)).

The Department has previously noted that, in order for reimbursed costs associated with overseas employees of National Grid plc to be recovered through rates, such costs must benefit Massachusetts customers, be reasonable, and be prudently incurred. D.P.U. 10-55, at 455-456 (2010).[191] Since its last rate case, the Company modified its accounting of non-business related expatriate expenses (Exh. DPU-1-25, at 3). Specifically, a third-party vendor in the United Kingdom now manages non-business related expenses incurred by expatriate employees (Exh. DPU-1-25, at 3). All non-business related expenses are: (1) reviewed and approved before the expatriate employee is reimbursed by the third-party vendor; (2) charged to the parent company; and (3) borne by shareholders (Exh. DPU-1-25, at 3). Business-related expatriate expenses are charged through the normal employee expense reimbursement system

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190 Pursuant to a settlement agreement between the Company and the Attorney General in Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-155-A (2014), one-third of external cost comparisons (i.e., corporate affairs; human resources; network strategy; safety, health, and wellness; and shared services), were developed as of March 31, 2015 (Exh. DPU-25-19, Att.). D.P.U. 10-155, Settlement Agreement at § 5. One-third (i.e., customer; information services; operations (including operations support, emergency planning, project management & complex construction, and process excellence); and strategy, business development and technology) were developed as of March 31, 2016 (Exh. DPU-25-19, Att. (Supp.)). The final third of remaining functions (i.e., audit, finance, legal, procurement, and regulation and pricing) will be developed by March 31, 2017 (Exh. DPU-25-19).

191 Reimbursed costs include moving costs, house rentals, annual vacations to the employee's home country, and health insurance costs that exceed those covered by the employee's home country health insurance.

(Exh. DPU-1-25, at 3). Based on the foregoing, the Department finds that the NGSC expenses charged to National Grid were charged at a competitive and reasonable price.

d. Allocation

Finally, we evaluate the method of allocating costs from NGSC to National Grid. When allocating costs among affiliates, it is preferable that costs associated with a specific utility are directly assigned to that utility. In the absence of a clear relationship between the cost and the affiliate, or when costs cannot be directly assigned, these costs are preferably allocated using cost-causative allocation factors to the extent such allocation factors can be applied, with general allocation factors used to allocate any remaining costs. D.P.U. 13-75, at 188; D.P.U. 11-01/D.P.U. 11-02, at 318-321; D.P.U. 10-114, at 271-274.

As previously stated, NGSC charges are charged directly to the Company, or when direct assignment is not possible, through allocation factors (Exh. NG-RRP-1, at 12). To ensure accuracy of the allocations, the Company requires employees to attend an in-depth enterprise-wide training program so that they charge their time and expenses appropriately (Exh. DPU-1-25, at 2). Further, all service company employees are required to take computer-based allocation training, and refresher training annually, developed and maintained by the Cost Allocations Compliance ("CACP") team (Exh. DPU-1-25, at 2). The CACP team also maintains and updates National Grid's cost allocation manual ("CAM"), which is stored on the Company's intranet and is readily accessible to all employees (Exh. DPU-1-25, at 3). The CAM explains the methods of allocating service company costs (Exh. AG-1-92). National Grid provided detailed information on all allocation codes and the metrics used to calculate them during the test year (see Exh. AG-1-92, Atts. 2 & 3).[192] The Department has reviewed these allocation codes and metrics and finds them to be cost-effective and nondiscriminatory.

It is the Company's policy to review all new service company internal requisitions for the appropriateness of the allocations prior to it being set up in SAP (Exh. DPU-1-25, at 3). Moreover, the service company accounting and finance employees circulate monthly reports of service company costs to each of the jurisdiction (e.g., Massachusetts) finance teams, who will review the appropriateness of those costs allocated or direct charged to each individual company within their jurisdiction (Exh. DPU-1-25, at 3). Additionally, the Company investigates variances greater than ten percent of the prior year's monthly bill (Exh. DPU-1-25, at 3). Further, National Grid reviews invoices from the service company that are greater than $10,000 to determine that the costs benefit the Company, and that the allocation is appropriate (Exh. DPU-1-25, at 3).

Additionally, as noted above in Section III, the Company retained PwC, an independent public accounting firm, to assist with the review of the costs charged from NGSC to National Grid in the test year (Exh. NG-RRP-1, at 7). PwC concluded that the costs were recorded accurately, and, on a net basis, that the costs were allocated appropriately pursuant to the Company's CAM (Exh. NG-RRP-1, at 10; NG-RRP-3).

4. Conclusion

Based on the foregoing, we find that National Grid has sufficiently demonstrated that the service company allocations are: (1) for activities that specifically benefit the Company and that

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192 These codes are updated at the beginning of each fiscal year (or when there is a significant change in the business) based on the prior calendar year numbers (Exh. AG-1-92).

do not duplicate services already provided by National Grid; (2) made at a competitive and reasonable price; and (3) allocated to the Company by a method that is both cost-effective and nondiscriminatory. Other sections of this Order address issues related to NGSC costs specific to those categories of costs.

O. Information Systems and Facilities Lease Expense

1. Introduction

a. Overview

National Grid's information systems ("IS") and facilities rent expenses represent charges billed to the Company for computer and information systems and leased facilities provided by NGSC (Exh. NG-RRP-1, at 20, 31-32).[193] NGSC owns the IS assets and bills its affiliated companies, including MECo and Nantucket Electric, their respective pro-rated share of costs including depreciation and a return component (Exhs. NG-RRP-1, at 31-32; NG-RRP-2, at 15). Additionally, NGSC bills the Company for use of facilities in Northborough[194] and Waltham, along with other Massachusetts locations, as well as for facilities in New York, Rhode Island, and Washington, D.C. (Exhs. NG-RRP-2, at 15; AG-2-24; DPU-31-23; DPU-31-24).[195] NGSC

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193 The Company refers to capital recovery-type charges associated with leased facilities and NCSC's IS investments as "asset recovery charges" (Exh. NG-RRP-2, at 15 (Rev. 3)). In this Order, we use the term "rent" for ease of reference.

194 Although MECo owns the Northborough facility, the facility is shared with other affiliates. Thus, the total costs related to the site are initially billed to NGSC, which then allocates those total costs to the operating entities sharing use of the facility (Exh. DPU-31-24).

195 There are corporate offices, government relations offices, and operations centers located in New York, Rhode Island, and Washington, D.C. (Exh. AG-2-24). The Company has removed $49,780 in costs associated with the Washington, D.C. office on the basis that

allocates both IS and facilities costs using a coding system that apportions the costs by an affiliate's percentage share of expenses or use of space measured in square feet (Exhs. NG-RRP-4, at 4; WP-NG-RRP-8; DPU-31-19; DPU-31-20; DPU-31-23; AG-1-92; AG-15-18; Tr. 5, at 603).

NGSC uses various methods for calculating rental charges for various facilities and information systems (Exh. AG-11-2, Att. at 1-17). Depending upon the particular facility and information system, NGSC will allocate their associated costs among its affiliates based on: (1) direct assignment; (2) a three-point allocation system; (3) customer counts; (4) cost causation; and (5) in the case of the Sutton warehouse,[196] a weighted average cost calculation of historical inventory (Exhs. NG-RRP-4, at 3-5; DPU-14-6; DPU-31-16; DPU-31-19; DPU-31-20; DPU-31-23; DPU-31-24; AG-1-92, Att. 1, at 29; AG-11-2; AG-11-3).[197]

b. SAP Consolidation Program

IS rent in the instant case is associated with new and enhanced information technology ("IT") assets upgraded as part of a larger IS consolidation and modernization conducted by National Grid USA starting in 2010 and affecting all National Grid USA affiliates

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this facility is primarily used for government relations, including lobbying activities (Exh. WP-NG-RRP-8, at 1).

196 The Sutton warehouse is National Grid's New England Distribution Center on the Sutton/Northbridge town line (Exh. DPU-14-6). See also, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 10-112-A at 2 (2013).

197 The Company's three-point allocation method employs data on net margin, net plant, and O&M expense to apportion expenses to the various operating companies (Exhs. AG-1-92, Att. 1, at 29; AG-11-2; AG-11-3; DPU-31-16; DPU-31-19; DPU-31-20).

(Exhs. NG-MLR-1, at 26-27; NG-RRP-1, at 32; Tr.1 at 46-49; Tr. 5, at 577-578).[198] Under the project name U.S. Foundations Program ("USFP") and employing an SAP Enterprise Resource Planning platform, NGSC sought to consolidate multiple legacy technology platforms brought together by the acquisition of KeySpan in August 2007 (Exhs. NG-MLR-1, at 26-27; AG-4-4; Tr. 5, at 577-578).[199] Both capital project costs and ongoing maintenance costs for new and enhanced data management systems deployed for outage management, finance, performance reporting, and other business processes such as payroll, supply chain, and IT delivery are included in the rent charge (Exh. NG-RRP-4, at 1-2; Tr. 5, at 597).

2. Company Proposal

a. Introduction

During the test year, National Grid booked $31,651,504 in facilities and IS lease expense, consisting of $9,031,383 in facilities rent expense, $1,357,905 in NGSC charges associated with depreciation and a return on facilities, and $21,262,215 in IS rent and operating charges (Exh. NG-RRP-2, at 15 (Rev. 3)).[200] The Company proposes to recover a total of $38,519,355 for facilities and IS expenses incurred during the test year and through the end of the rate year, September 30, 2017 (Exh. NG-RRP-2, at 15 (Rev. 3)).[201] The Company's proposal to increase

198 The IS consolidation project required approval from the board of directors of National Grid plc but was managed by National Grid USA (Exhs. AG-4-4; Tr. 5, at 571-572).

199 The Company launched the initial USFP modules in November 2012, but problems with implementation prompted a corrective stabilization program that ran until September 2014 (Exhs. NG-MLR-1, at 27-28; AG-4-20).

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

201 Of this amount, $29,732,078 represents IS lease expenses and $8,787,277 is associated with facilities lease expense (Exh. NG-RRP-2, at 15 (Rev. 3)).

facilities and IS lease expense is based on what the Company represents are known and measurable adjustments of $10,127,504, as discussed below (Exh. NG-RRP-2, at 15 (Rev. 3)).

b. Normalizing Adjustments

The facilities and IS adjustments include normalizing adjustments of $3,259,652, consisting of: (1) a decrease of $1,602,011 for restated test year facilities rental expense; and (2) a decrease of $1,657,641 from the Company's test year share of IS rent billed for NGSC-owned systems in service as of June 30, 2015 and restated to an annual asset recovery amount (depreciation and return) for the rate year ending September 30, 2017 (Exhs. NG-RRP-1, at 20; NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1).[202] These adjustments produced a normalized test year facilities and IS expense total of $28,391,851, consisting of $8,787,277 in facilities lease and depreciation and return expense and $19,604,574 in IS rent expense (Exh. NG-RRP-2, at 15 (Rev. 3)).

c. Post-Test Year IS Adjustments

Along with its proposed test year normalization adjustments, the Company proposed an increase of $10,127,504 for post-test year IS rent charged by NGSC related to the implementation of new data management systems placed into service by May 31, 2016, and their associated ongoing support and maintenance costs (Exhs. NG-RRP-1, at 31-32; NG-RRP-2, at 15 (Rev. 3); Tr. 5, at 596). Of the proposed $10,127,504 increase, $9,026,666 in IS rent expense involves NGSC capital additions and enhancements for the rate year ending September 30, 2017 (Exhs. NG-RRP-1, at 32; NG-RRP-2, at 15 (Rev. 3); NG-RRP-4, at 1-2 (Rev. 1)).

202 The Company bases its test year normalization adjustment for both facilities and IS rents on a projected average NGSC depreciation balance for a twelve-month period between October 1, 2016 and September 30, 2017 (Exhs. NG-RRP-4, at 3-5; WP-NG-RRP-8, at 2-4; AG-ADR-1, at 25, lines 18-19).

These new systems and enhancements include $5,619,623 associated with a new outage management system ("OMS") placed into service on December 4, 2015; $2,504,315 for the USFP SAP Enhancement One ("EHR1") project, most of which went into service in November 2015; and $902,728 for other IS investments placed into service between October 2015 and May 2016 (Exhs. NG-RRP-4, at 1-2 (Rev. 1); NG-RRP-Rebuttal-1, at 20; NG-RRP-Rebuttal-4, at 1, 6; AG-DR-1, at 22).[203] Additional incremental ongoing operation costs of $574,716 for OMS and $526,122 for the energy management system ("EMS") complete the $10,127,504 total proposed adjustment (Exh. NG-RRP-2, at 15 (Rev. 3); NG-RRP-4, at 1-2 (Rev. 1)).

d. Facilities Lease Expense

As noted above, along with the IS increases, National Grid proposed to recover $9,031,383 in test year facilities rent expense and $1,357,905 in test year NGSC charges associated with depreciation and a return on facilities (Exh. NG-RRP-2, at 15 (Rev. 3)). These expenses are related to office space, control centers, training facilities, and warehouses (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1). The Company leases space for corporate offices, government relations, operations, training, and warehousing at facilities in Boston, Gardner, Monson, Sutton, Uxbridge, and Waltham (Exhs. NG-RRP-2, at 15 (Rev. 3);

203 In rebuttal testimony, the Company agreed to exclude from its calculation of rate year IS rental expense the costs for any delayed projects not placed into service by May 31, 2016 (Exh. NG-RRP-Rebuttal-1, at 20). The Company subsequently reduced the rate year IS rental expense by $679,371 for delayed projects, while subtracting an additional $62,834 for costs related to updated USFP EHR1 investment information (Exhs. NG-RRP-Rebuttal-1, at 20 n.8; NG-RRP-Rebuttal-4, at 1; DPU-31-21, Att., at 2).

WP-NG-RRP-8, at 1; DPU-31-23; DPU-31-24; AG-2-24, Att.).[204] The Company also owns a facility in Northborough (Exhs. NG-WP-RRP-8, at 1; DPU-31-24). For the test year ending June 30, 2015, the Company made $1,602,011 in normalizing adjustments, consisting of corrections to various allocations, inflation, and test year true ups of prior year rent expenses (Exhs. NG-RRP-1, at 20; NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1 and 8; DPU-31-24). Therefore, the Company's adjusted test year amount of facilities lease expense and associated expense is $8,787,277 (Exh. NG-RRP-2, at 15 (Rev. 3)). The Company proposed no post-test year adjustments related to facilities rent (Exh. NG-RRP-2, at 15 (Rev. 3)).

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

a. <u>Attorney General</u>

i. <u>Overview</u>

The Attorney General argues that the Department should: (1) reject the Company's proposal to include post-test year IS adjustments through September 30, 2017; (2) exclude the IS rent expense on NGSC's books associated with IT systems closed to plant in service after the end of the test year; (3) remove incremental expenses associated with post-test year IS additions; (4) remove non-recurring test year EHR1 implementation expenses; (5) reduce the equity return applied to the NGSC IS assets to 7.80 percent; (6) reduce the return on USFP SAP assets to 3.7 percent; and, if the Department ultimately finds it appropriate to include those post-test year additions, (7) incorporate anticipated savings from post-test year IS additions into the Company's cost of service (Attorney General Brief at 40, 126; Attorney General Reply Brief

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[204] The Company breaks down the total facilities cost as follows: $3,308,931 for Reservoir Woods in Waltham; $1,462,878 for Northborough; and $4,015,468 for all other facilities (Exh. NG-RRP-2, at 15 (Rev. 3)).

at 71).[205] The Attorney General did not comment on brief about the Company's facilities expense.

ii. Test Year IS Expenses

The Attorney General argues that it is inappropriate to include IS rent expense charges associated with NGSC's net plant in service and associated accumulated deferred income taxes balances for the post-test year period ending September 30, 2017, as proposed by the Company (Attorney General Brief at 41). She argues that no compelling reason exists in the instant case to calculate the charges to the Company from NGSC for NGSC's recovery of and return on its assets based on a period that extends 15 months beyond the end of the test year (Attorney General Brief at 41).

The Attorney General rejects any notion that excluding the post-test year IS rent expense will create a significant shortfall in the Company's rate recovery and cause the potential loss of more than half of its IS investment (Attorney General Reply Brief at 19). According to the Attorney General, the Department's denial of recovery of post-test year investments would not be unreasonable or unfair because after the end of the test year, the investments in service during the test year continue to be depreciated while the post-test year increase in the accumulated depreciation would not be subtracted from rate base (Attorney General Reply Brief at 19). Additionally, the Attorney General contends that even though some projects may be retired from service after the test year end, they would remain in rate base (Attorney General Reply Brief

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205 In her original brief, the Attorney General proposed reducing the ROE associated with IS assets from the 10.5 percent ROE incorporated in the Company's original filing to 8.50 percent (Attorney General Brief at 40). Subsequently, the Attorney General recommended setting the allowed ROE at 7.80 percent (Attorney General Brief at 126, citing Exhs. AG-JRW-1, at 51 and 60–61; Attorney General Reply Brief at 71).

at 19). Therefore, the Attorney General recommends that the Department reject the Company's proposal to extend the net balance of NGSC IT assets in place at the end of the test year through the twelve-month period ending September 30, 2017 (Attorney General Brief at 42).

iii. Post-Test Year IS Additions

The Attorney General also opposes the inclusion of any post-test year IS plant in the computation of National Grid's IS expense (Attorney General Brief at 41-42). The Attorney General notes that the Department generally does not recognize post-test year additions to rate base, unless the utility demonstrates that the additions are significant relative to the test year-end rate base (Attorney General Brief at 41, citing D.P.U. 14-150, at 43-44). The Attorney General contends that the Company presents no argument or evidence supporting a change to the cited precedent (Attorney General Brief at 42).

The Attorney General argues that the Company's post-test year IS plant additions represent only a small fraction of NGSC's total IS investment used by the Company (Attorney General Brief at 42; Attorney General Reply Brief at 16-18). In support of her contention, the Attorney General notes that MECo was allocated 18.58 percent and Nantucket Electric was allocated 0.27 percent for their respective portions in the majority of projects included in NGSC's total $145.67 million post-test year IS investment (Attorney General Brief at 42; Attorney General Reply Brief at 18). Thus, she claims that the amount ultimately allocated to the Company through the NGSC IS rental expense is insignificant when compared to the Company's $2.3 billion of net plant and $1.79 billion requested rate base in the instant case (Attorney General Brief at 43; Attorney General Reply Brief at 18). The Attorney General maintains that when determining the significance of a post-test year adjustment, a company's rate base, not the amount of rate base or investment held by an affiliated entity, is the relevant factor (Attorney General Reply Brief at 17).[206]

Moreover, the Attorney General argues that the 13 separate projects comprising the relevant plant additions are individually insignificant when compared to the Company's rate base (Attorney General Brief at 43). The Attorney General notes that Department precedent considers individual plant investments and not combined plant additions in determining substantive impact on rate base (Attorney General Reply Brief at 17). She asserts that the Department should not allow the Company to obscure the purity of the test year by introducing post-test year investments of an affiliated entity against well-established Department precedent for the limited consideration of post-test year plant additions in rates (Attorney General Reply Brief at 18).

Consequently, the Attorney General recommends that the Department exclude the entire $9,026,666 in post-test year NGSC IT plant additions placed into service between October 2015 and May 2016 from the calculation of IT expenses (Attorney General Brief at 42).[207]

iv. Incremental OMS Expense

The Attorney General notes that National Grid seeks to include $574,716 in projected operating expenses associated with the OMS implemented by NGSC after the end of the test year (Attorney General Brief at 44, citing Exh. NG-RRP-2, at 15). Consistent with her proposed

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206 The Attorney General notes that the Company instead limits its comparison of the post-test year IS plant additions to NGSC's total net investment in IS systems (Attorney General Reply Brief at 17).

207 During the proceedings, the Attorney General offered an alternative set of adjustments in the event that the Department allowed post-test year NGSC plant additions (Exhs. AG-DR-1, at 41-48; AG-DR-3, Schs. 1-4). On brief, the Attorney General discussed some of the alternative adjustments proposed by her witness (Attorney General Brief at 48-50).

removal of post-test year NGSC plant additions, the Attorney General argues that $574,716 in incremental expenses associated with projected OMS operating costs should be removed from the Company's cost of service (Attorney General Brief at 44).

v. SAP Enhancement Release 1 Expenses

Fourth, the Attorney General argues that $2.7 million in costs associated with EHR1 should be removed from the adjusted test year rent cost as a non-recurring item (Attorney General Brief at 48). She argues that the EHR1 represents another step and update in the overall SAP system that was included in the post-test year NGSC IS plant additions, and that while the Company agreed in rebuttal to reduce the $2.7 million expense to $2.3 million through amortization over seven years, the entire $2.7 million should be excluded from cost of service (Attorney General Brief at 49, citing Exh. NG--RRP-Rebuttal-1, at 28).

vi. Return on USFP SAP System Assets

The Attorney General argues that the return on USFP SAP system assets should be reduced because of (1) the extent of the problems the Company experienced with the USFP SAP implementation, (2) the Company's imprudence, and (3) the effect of these implementation problems on the Company's operations, including cost overruns and the need for subsequent system stabilization efforts (Attorney General Brief at 45-47, citing Exhs. NGRRP-9, at 3; AG-DR-1, at 31-32, 33-35; AG-4-4; AG-23-9, Att. 1; Tr. 5, at 586, 607-608; Attorney General Reply Brief at 20). The Attorney General claims that the Company attempts to gloss over the serious USFP SAP problems (Attorney General Brief at 21). She maintains that the Company itself identified the problems in USFP post-implementation review documents that reflect actions that were not reasonable or prudent (Attorney General Reply Brief at 21-22, citing Exhs. AG-4-6, Att. 66; AG-23-9, Att. 1).[208] Additionally, the Attorney General challenges the inclusion of certain USFP SAP Release 3 ("R3") stabilization costs in the IS rent expense that further drive up costs to ratepayers, and despite the Company's claim that all SAP stabilization costs were charged to the parent (Attorney General Brief at 47).

In light of what the Attorney General considers to be the severity of the implementation problems and imprudence of the root causes, she recommends that the return component be limited to NCSC's 3.70 percent long-term debt rate (Attorney General Brief at 47-48; Attorney General Reply Brief at 20, 22). The Attorney General avers that the combination of the lower 3.70 percent return and limiting the inclusion of NGSC's IS net assets to the test year-end balance as discussed above would further reduce IS rent expense by $2,271,485 (Attorney General Brief at 48).

vii. Rate of Return on IS Assets

The Attorney General challenges the Company's proposed use of a 10.63 percent overall pre-tax return to the NGSC IS assets in determining the rent expense, arguing that the ROE component of the 10.63 percent rate should be revised to the allowed ROE approved by the Department in this case (Attorney General Brief at 43). She states that the Company agreed in its rebuttal that the NGSC rent expense should be based on the ROE approved by the Department (Attorney General Brief at 43, citing Exh. NG-RRP-Rebuttal-1, at 20). Based on her recommended ROE of 7.80 percent, the Attorney General states that the revised return results in

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[208] Exhibit AG-23-29, Attachment 1 is a copy of an October 2013 presentation to members of the New York State Public Service Commission as part of the Comprehensive Management and Operations Audit of National Grid USA's New York Gas Companies (Case No. 13-G-0009). Exhibit AG-4-6, Attachment 66 is a confidential report titled "USFP R1 Review: Lessons Learned" that was prepared by a consultant and dated November 29, 2014.

a reduction to the Company's proposed IS rent expense (Attorney General Brief at 43-44, citing Exh. AG-DR-2, Sch. 7, at 1 and 2).[209] Therefore, the Attorney General recommends reducing the equity return applied to NGSC IS assets from the 10.50 percent ROE incorporated in the Company's original filing to the 7.80 percent recommended by the Attorney General in this case (Attorney General Brief at 40; Attorney General Reply Brief at 71).

viii. Imputed EHR1 Savings

The Attorney General argues that if the Department allows the inclusion of post-test year EHR1 system plant additions in the determination of NGSC rent expenses, the Company also should net out the associated cost savings that the enhancements generate (Attorney General Brief at 49; Attorney General Reply Brief at 23). In support of her position, the Attorney General states that the Company had identified potential estimated cost savings associated with the EHR1 projects that would begin accruing by the middle of 2016 (Attorney General Brief at 49; Attorney General Reply Brief at 23). Citing the Company's figure of $6.46 million in potential savings at the service company level and applying an 18.85 percent[210] allocation factor used to determine MECo and Nantucket Electric's combined portion of expenses and adjustments, the Attorney General recommends reducing the IS rent expense by $1,217,710 to incorporate projected costs savings (Attorney General Brief at 49-50, citing Exhs. AG-DR-1,

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209 The Attorney General notes that her calculation of the reduction to IS rent expense using a pre-tax return of 8.96 percent offered on brief does not include any potential additional disallowances or ROE reductions associated with the USFP SAP systems implementation (Attorney General Brief at 44). She addresses these proposed adjustments elsewhere in her brief (Attorney General Brief at 44-48).

210 The 18.85 percent allocation factor represents the combined allocations of 18.58 percent for Massachusetts Electric and 0.27 percent for Nantucket Electric (Exh.WP-NG-RRP-9, at 5-8).

at 48; AG-DR-3, Sch. 4; AG-23-11; Attorney General Reply Brief at 23). Excluding these cost savings, the Attorney General maintains, will further hinder efforts to match revenues, expense, and investments in a revenue requirement equation already distorted by the inclusion of the post-test year rent expense (Attorney General Reply Brief at 23).

b. Company

i. Overview

National Grid maintains that the $38,519,355 in total IS and facilities rental expenses, comprising normalized test year expenses of $28,391,851 and an additional $10,127,504 in post-test year adjustments, are reasonable and prudently incurred, and therefore should be included in the cost of service (Company Brief at 31; Company Reply Brief at 33, citing Exh. NG-RRP-2, at 15 (Rev. 3)). The Company argues that the Attorney General's recommendations to eliminate certain IS rental expenses from cost of service are without merit and should be rejected by the Department (Company Brief at 31).

In support of its IS rental proposals and in opposition to the Attorney General's recommendations, the Company emphasizes that: (1) the post-test year IS adjustments are significant and prudent; (2) there is no basis for a reduced return on USFP; (3) the EHR1 implementation expense should be allowed; and (4) savings should not be imputed (Company Brief at 32-44; Company Reply Brief at 24-33). Noting that the Attorney General did not contest the proposed facilities rental expenses, the Company states that the Department should approve recovery of the facilities rental costs without modification (Company Brief at 31 n.10, 37).

ii. Post-Test Year IS Additions

The Company dismisses the Attorney General's recommendation to remove $9,026,666 in incremental IS rental charges from NGSC, related to post-test year NGSC IS plant additions (Company Brief at 31-32, citing Attorney General Brief at 41-42). The Company also contests the Attorney General's opposition to post-test year plant additions as the basis for normalization adjustments associated with NGSC rate base balances (Company Brief at 32-33).

The Company asserts that the IS projects at issue represent significant NGSC investments (Company Brief at 33-34; Company Reply Brief at 29). In particular, the Company notes that approximately $9.0 million in post-test year rent expense associated with the NGSC IS rental charges is greater than two percent of the Company's total distribution O&M expense portion of its cost of service (Company Brief at 34). The Company argues that the Attorney General obscures the facts of the investment by referring to the Company's allocated portion of the rental fees instead of the actual dollar amounts associated with the NGSC IS investments (Company Brief at 34). According to the Company, the total NGSC investment associated with the IS projects in question is $145,672,554, and represents over 41 percent of the NGSC's total net IS investment of $350,629,068, thereby reinforcing the significance of the amounts both for the Company and for NGSC (Company Brief at 34, citing Tr. 6, at 948, 951-952; Company Reply Brief at 26).[211]

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211 National Grid's witness stated that the Company proposed to recover the post-test year IS rental expenses as operating expenses rather than as a rate base item, which would earn a return for the Company (Tr. 6, at 948, 951). The same witness, however, also stated that the NGSC calculation of the IS rental expense allocated to MECo and Nantucket Electric included a return on capital at the service company level (Tr. 6, at 948-949).

The Company presents alternative interpretations of the significance standard in opposition to the Attorney General's arguments (Company Reply Brief at 25-27). First, the Company disputes the Attorney General's contention that significance should be determined on an individual project basis and not on a collective basis (Company Reply Brief at 25-26). According to the Company, there is no rule or practice set by the Department that precludes consideration of the IS investments as a group (Company Reply Brief at 26). Additionally, the Company avers that the IS projects in question are part of an interrelated series of improvements to information systems necessary to serve customers (Company Reply Brief at 28).

Second, the Company maintains that there is no requirement that a capital investment must be significant in relation to the Company's own rate base and not the amount of rate base or investment held by an affiliated entity, even if the investment is made by the affiliated entity (Company Reply Brief at 26). Nor would such a rule make sense, the Company contends, when the investments will be recorded on the Company's books as expense and not as capital (Company Reply Brief at 26). On a related matter, the Company disagrees with the Attorney General's discounting of IS project cost comparisons to total net investments in IS systems, arguing that the Attorney General overlooks the fact that as a service company, the bulk of NGSC's assets would be IS rather than distribution plant or other booked rate base items (Company Reply Brief at 26). The Company notes that NGSC's total net investment in IS at the end of the test year (i.e., June 30, 2015) represented 36 percent of the service company's total rate base of $862,881,567 (Company Reply Brief at 26, citing NGSC's 2015 FERC Form 60).

Third, the Company takes issue with the Attorney General's claim that MECo and Nantucket Electric's shared 18.85 percent allocated portion of the $145.67 million IS rental expense disqualifies the significance of the Company's stake in the total (Company Reply Brief at 26-27). Such an argument, the Company maintains, ignores the rationale of a holding company structure, which is to provide benefits to each operating company in relation to shared services, particularly in the area of IS where operating affiliates can obtain access to systems they could not afford on their own (Company Reply Brief at 27). It will always be the case, the Company argues, that the share of costs paid by individual operating companies may not be significant relative to the whole (Company Reply Brief at 27). Therefore, the Company adds, if all the smaller allocated portions of operating company IS rental expenses are deemed to be insignificant, then it is not possible for NGSC to recover its costs (Company Reply Brief at 27).

For these reasons, the Company contends that the Department cannot reasonably rely on a comparison of the allocated share of expense to the whole expense when determining whether the post-test year IS rent charges in the instant case are significant and therefore eligible for cost recovery (Company Reply Brief at 27). Rather, it recommends that the Department consider the comparison provided by the Company as the signal for whether cost recovery is warranted, i.e., a comparison of NGSC's $145.67 million of plant additions to $350,629,068 total net IS investment (Company Reply Brief at 27).

Additionally, the Company argues that excluding the post-test year change in IS rental expense associated with post-test year NGSC IS investments would cause the Company to experience a significant shortfall in its rate recovery, since all of the IS projects requested for inclusion in rates have seven-year amortization periods, which are far shorter than depreciation periods for typical utility plant and amount to nearly $40 million in amortized asset recovery

(Company Brief at 36; Company Reply Brief at 29, citing Exh. NG-RRP-Rebuttal-4, at 5).[212] The Company contends that if the Department accepted the Attorney General's recommendation to deny inclusion of post-test year IS rental expenses, the decision could potentially cause the Company to lose more than half of its IS investment even with a short period between base-rate cases (Company Brief at 36; Company Reply Brief at 29). The decision, according to the Company, would be tantamount to disallowing a substantial portion of the investment without any finding of imprudence, and despite the fact that the investments in question are in service and benefitting customers (Company Brief at 37; Company Reply Brief at 29).

Based on the foregoing analysis, National Grid concludes that the Department should reject the Attorney General's recommendation and instead authorize the inclusion of IS rental expense associated with the post-test year NGSC IS investments (Company Brief at 37). Consistent with this treatment, the Company urges the Department to allow the inclusion of incremental OMS operating expenses in the Company's cost of service (Company Brief at 37).

iii. SAP EHR1 Expenses

In response to the Attorney General's recommendation to remove $2.7 million in EHR1 system expenses as a non-recurring item, the Company argues that the appropriate treatment of this expense is to amortize it, as supported by Department precedent (Company Brief at 42). The Company contends that the Attorney General's recommendation of complete disallowance has no basis insofar as she fails to support any claim that the IS rental expense associated with the

[212] The Company cites to $38,216,613 in projected accumulated amortization, derived from subtracting a balance of $107,455,613 representing the total value of NGSC IS project investments at September 30, 2017 from the forecast total NGSC IS expense of $145,672,554 incurred between June 30, 2015 and May 31, 2016 (Exhs. NG-RRP-Rebuttal-1, at 20; NG-RRP-Rebuttal-4, at 5).

EHR1 system is indeterminate, unreasonable, or imprudent, and that she fails to demonstrate that the seven-year amortization period is inappropriate (Company Brief at 42-43).

National Grid argues that IT expenses, such as the EHR1 expenditures, are amortized over time in a way that strikes a balance between the need to continue improvements in service technology and the need to maintain intergenerational integrity (Company Brief at 42, citing D.P.U. 13-75, at 217; D.T.E. 02-24/25, at 153; Boston Gas Company, D.P.U. 93-60-D at 4 (1994)). Because the EHR1 system is being amortized over seven years, the Company reasons that the related EHR1 implementation expenses should be amortized as well (Company Brief at 42, citing Exhs. NG-RRP-Rebuttal-4, at 1; NG-RRP-2 (REV-2), at 15). Accordingly, the Company recommends that the Department reject the Attorney General's argument and authorize the proposed amortization of EHR1 expense (Company Brief at 43).

iv. Return on USFP SAP Assets

National Grid contests the Attorney General's argument for reducing NGSC's return to the 3.70 percent long-term debt rate based on problems and imprudence associated with the USFP system implementation (Company Brief at 37; Company Reply Brief at 30-32). The Company asserts that the Attorney General's recommended penalty of a reduced return on the USFP system is unwarranted because the implementation issues were caused by factors the Company already explained, factors that did not include the types of unreasonable decisions made during project development that meet the requirements for a finding of imprudence

(Company Brief at 38-39, citing Exh. NG-RRP-Rebuttal-1, at 27; Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983)).[213]

The Company specifically challenges the testimony of the Attorney General's witness, who argued that the Company should have anticipated the problems with the USFP implementation given difficulties with roll outs of SAP systems at other companies (Company Reply Brief at 30-31). The witness, according to the Company, readily admitted no technical or practical experience with SAP implementation (Company Reply Brief at 30, citing Tr. 15, at 1593-1594, 1599; Attorney General Reply Brief at 20). Conversely, the Company asserts that it demonstrated that complex, multi-layered IS investments such as USFP SAP cannot simply be compared to other companies' SAP implementation experiences, whether utilities or not (Company Reply Brief at 31, citing Tr. 5, at 600).[214]

The Company also challenges the Attorney General's reliance on a report to the NYPSC expounding on issues encountered in the USFP SAP implementation and lessons learned as the basis for an imprudence finding on the equity return component of the USFP rental expense (Company Reply Brief at 31-32, citing Attorney General Reply Brief at 22;

213 The Company notes that a review of the prudence of a company's actions is not dependent on whether budget estimates later proved to be accurate, but rather upon whether the assumptions made were reasonable given the facts known at the time (Company Brief at 39, citing D.P.U. 95-118, at 39-40; D.P.U. 93-60, at 35; D.P.U. 84-145-A at 26).

214 The Company's witness testified that it is difficult to compare large, complex software projects across utilities or across companies in general since the systems, which are generally located at the center of a company's operations and interface with a number of other systems, are designed specifically in recognition of the environment in which they must function (Company Reply Brief at 31, citing Tr. 5, at 600).

Exh. AG-4-6, Att. 66).[215] According to the Company, the Attorney General misses the fact that the report's findings helped propel National Grid USA to write off $552 million in shareholder value associated with the USFP SAP implementation to shield customers from the financial impact of the implementation problems (Company Reply Brief at 32). The Company also notes that the NYPSC determined that the remaining costs were recoverable through customer rates, and, therefore, authorized Niagara Mohawk Power Corporation and Brooklyn Union Gas Company, both National Grid operating companies in New York, to recover the same category of USFP SAP costs included in the instant case (Company Reply Brief at 32, citing Exh. NG-ISP-Rebuttal-1, at 18). The Company avers that if the remaining costs were subject to disallowance on the basis of the report findings, the NYPSC would have come to that conclusion (Company Reply Brief at 32).

Further, the Company contests the Attorney General's claim that R3 stabilization costs were inappropriately included in its proposed revenue requirement (Company Brief at 38). The Company asserts that it included only the portion of R3 investment attributable to system enhancements to add functionality to the SAP system and not to stabilize it (Company Brief at 38).

In sum, the Company argues that the Attorney General provided no justification to meet the imprudence standard, and that National Grid was forthcoming in voluntarily excluding all capital and O&M costs associated with system stabilization made necessary by implementation issues (Company Brief at 39). Further, the Company maintains that the Attorney General's recommended ROE adjustment is not based on any specific cost element or showing that the

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215 See n.208 above.

costs were not actually incurred or are computed incorrectly, or any other substantive basis (Company Brief at 40).[216] Therefore, the Company recommends the Department reject the Attorney General's adjusted ROE (Company Brief at 42).

v. Imputed EHR1 Savings

National Grid opposes the Attorney General's recommendation to impute $1.2 million in projected EHR1 project savings to the Company's revenue requirement (Company Brief at 43). The Company argues that the Attorney General's reliance on potential estimated cost savings ignores record evidence showing no basis for making such an adjustment (Company Brief at 43).[217] National Grid maintains that although it provides some quantitative analysis for prospective savings, this savings estimate was preliminary in nature, because (1) the estimates were made during the conceptual design phase of EHR1; (2) the majority of the quantitative benefits were associated with avoiding costs, the extent of which would not have been known until the actual execution of the projects; and (3) after four years of SAP implementation, stabilization and enhancement work, National Grid ultimately recognized that identifiable benefits were qualitative and not quantitative (Company Brief at 43, citing Exh. AG-23-11; Company Reply Brief at 33). The Company further claims that while the Attorney General acknowledged that potential savings were associated with avoided future costs rather than

216 The Company explained that the difference between pre-implementation estimates and final costs should not be viewed as the terminus of a one-dimensional systems replacement project, but rather the outcome of a complex, iterative design and planning effort integrating multiple business processes into the final scope of USFP SAP (Company Brief at 40-41, citing Exh. NG-ISP-Rebuttal-1, at 14-15).

217 The Company identified $6.46 million of potential cost savings, as discussed above, in response to an information request from the Attorney General asking for any updated quantifications of savings associated with SAP implementation (Exh. AG-23-11).

reduced existing costs, she chose to ignore the information when making her recommendation (Company Brief at 44, citing, Exh. AG-DR-1, at 47). Moreover, the Company maintains that the Attorney General did not reference any evidence showing either any realized net savings as a result of the EHR1 implementation or demonstrating that net savings are routinely expected from such system enhancements (Company Brief at 44; Company Reply Brief at 33).[218] The Company further asserts that the Attorney General failed to respond to evidence that the benefits of potential savings are qualitative and that achieving estimated savings depends on a multitude of factors that make realization difficult (Company Reply Brief at 33, citing Company Brief at 43; Exh. AG-23-11). Accordingly, the Company contends that the Department should disregard the Attorney General's recommendation to impute $1.2 million in projected EHR1 implementation savings to the revenue request (Company Brief at 44; Company Reply Brief at 33).

4. Analysis and Findings

a. Introduction

The Department first will review the Company's proposal for test year adjustments to rental expenses for leased facilities. The Company proposed adjustments to expenses for facilities in Northborough and Waltham, among other Massachusetts locations, and in New York, Rhode Island, and Washington, D.C. No intervenors commented on facilities lease expenses.

218 The Company noted a similar recommendation of the Attorney General's in D.P.U. 13-75 when she sought to offset costs of a NiSource financial platform, NIFIT, with purported savings from implementation of the platform (Company Brief at 44). The Company further noted that the Department rejected the Attorney General's recommendation, finding that the benefits of the NIFIT system were not necessarily quantifiable in monetary terms (Company Brief at 44, citing D.P.U. 13-75, at 114).

The Department will then examine evidence supporting National Grid's proposed revenue requests for post-test year IS rent additions. Specifically, the Department will decide whether the Company should: (1) recover costs related to post-test year IS rent adjustments, including the proposed $9,026,666 post-test year plant additions and associated incremental OMS operating expenses; (2) reduce NGSC's return on IS assets in general and on USFP SAP implementation costs in particular; (3) remove $2.7 million in EHR1 implementation costs; and (4) impute $1.2 million in projected savings to the revenue requirement.

In arriving at the findings, the Department will examine the following issues central to the Attorney General's opposition arguments: (1) use of the Company's rate base as the basis for measuring the significance of IS rent charges to MECo and Nantucket Electric; (2) the prudence of the USFP SAP implementation given problems with its roll-out; and (3) characterization of the non-recurring test year EHR1 implementation expense as a stabilization cost.

b. Facilities Lease Expense

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

During the test year, National Grid booked lease-related expenses totaling $8,787,277 for facilities, including $3,308,931 for Reservoir Woods, Waltham; $1,462,878 for Northborough;

and $4,015,468 for all other facilities (Exhs. NG-RRP-2 (REV-3), at 15; WP NG-RRP-8).[219] No intervenors commented on the Company's proposed facilities rental expense adjustments. The Department finds that the proposed adjustments to the Company's facilities lease expenses are reasonable and represent a known and measurable change to the Company's test year cost of service (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8; DPU-31-24; AG-1-64; AG-1-92). D.P.U. 10-55, at 260-268; D.P.U. 09-39, at 156-158; D.P.U. 95-118, at 42 n.24; D.P.U. 89-114/90-331/91-80 (Phase I) at 153. Accordingly, the Department accepts National Grid's proposed expense adjustments for its facilities.

c. Post-Test Year IS Additions

As noted above, the Attorney General opposes the Company's inclusion of $9,026,666 in post-test year IS rent expense, stating that these adjustments break with Department precedent requiring the utility to demonstrate that post-test year additions are significant relative to the operating company's test year end rate base. In turn, National Grid maintains that there is no basis for applying the Department's post-test year rate base standard to costs that are treated as expenses on a company's books.

In the instant case, the associated costs are not recorded as plant investment, but instead are recorded as expenses (Exhs. NG-RRP-1, at 12; NG-RRP-Rebuttal-1, at 22; Tr. 6, at 946-952). The Department has found that because lease expenses do not represent a capital improvement to the Company, such expenses should not constitute a rate base item. D.P.U. 09-39, at 155; D.P.U. 95-118, at 41-46; NYNEX Price Cap, D.P.U. 94-50, at 436 (1995);

219 As noted above in Section VIII.O.2.b, these lease-related expenses reflect normalizing adjustments totaling $1,602,011, representing a decrease to the total test year end amount (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8; DPU-31-24).

D.P.U. 84-94, at 18. The Department finds that rental expense is a component of a company's operating and maintenance expense, not a component of its capital structure. NGSC owns the IS assets in question and therefore its rate base applies to those assets. While the lease arrangements provide the Company with benefits from the IT system, they do not give the Company an ownership interest in the assets or permit the Company to include associated capital expenditures in rate base. D.P.U. 09-39, at 155; D.P.U. 85-270, at 186; D.P.U. 84-94, at 18. We also find that these IS rent expenses are known and measurable (Exhs. NG-RRP-2, at 15 (Rev. 3); NG-RRP-4 (Rev. 1); WP NG-RRP-9 at 4, 8, 12 (Rev. 1); AG-DR-1, at 39-40). Accordingly, the Department declines to accept the Attorney General's recommendation to exclude the Company's $9,026,666 in IS rent expense normalization from the adjusted test year expenses. However, as discussed below, the Department will adjust this amount based on NGSC's return on rate base.

Consistent with our disposition of this issue, the Department declines to adopt the Attorney General's recommendation to remove incremental OMS expenses of $574,716. Further, we find that incremental EMS expenses of $526,122 are appropriate for recovery. Therefore, the Department includes these expenses in the Company's cost of service.

d. Reduced NGSC Returns

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 non-discriminatory 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. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 143-146 (2012); D.P.U. 95-118, at 41; Milford Water Company, D.P.U. 92-101, at 43-46 (1992); D.P.U. 89-114/90-331/91-80 (Phase I) at 79-80 (1991); D.P.U. 85-137, at 51-52.

The Attorney General has recommended that the Department reduce the return portion of the IS rent expense on two levels. First, the Attorney General recommends that the return specifically associated with USFP SAP implementation costs be reduced to 3.70 percent, representing NGSC's long-term-debt rate. Second, the Attorney General recommends that the return on all NGSC IS asset-related costs be based on the ROE ultimately allowed by the Department; National Grid concurs with this second recommendation (Exh. NG-RRP-Rebuttal-1, at 20).

Regarding her recommendation to reduce the return on USFP SAP implementation to NGSC's long-term debt rate of 3.70 percent, the Attorney General draws on the extensive record evidence detailing USFP SAP implementation problems and subsequent corrective stabilization efforts to argue that Company denial of unreasonable decision making is an attempt to gloss over her legitimate claims of imprudence. The extent of the problems associated with USFP SAP implementation is acknowledged by the Company and is well-documented in the instant case (Exhs. NG-MLR-1, at 27-28; AG-4-6; AG-16-12; AG-23-9, Att. 1; Tr. 1, at 45-54; Tr. 5, at 598-600, 605-608).[220] NGSC executives explained details of the root causes, which the Attorney General cited as evidence of imprudence behind the decisions underpinning the USFP

[220] In particular, Exhibit AG-4-6 includes 72 attachments, covering USFP SAP implementation audits and update reports on system improvements resulting from NGSC's responses to identified problems and lessons learned (Exhs. AG-4-6; AG-23-9).

SAP development and roll-out (Exhs. AG-23-9, Att. 1; Tr. 1, at 45-54, 56-57; Tr. 5, at 607-608). The Attorney General focuses on increases in total projected costs throughout the project's development to attach a financial consequence to the problems experienced at implementation (Exhs. AG-DR-1, at 33-35; AG-4-4; AG-4-21). The Department, however, disagrees with the Attorney General's suggestion that the implementation problems and cost increases are linked and based on unreasonable and imprudent decisions.

Regarding increases in project costs, a prudence review of a company's actions is not dependent upon whether budget estimates later prove 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. 93-60, at 35; D.P.U. 85-270, at 23-24. Documents recording details of the early project scoping efforts indicate that the Company was aware that only final detailed design phases closer to project implementation would prove the accuracy and validity of preliminary project scoping and cost estimates (Exh. AG-4-4, Atts. 2-5). Overall, the record shows that NGSC embarked on a necessary update of critical but inadequate information systems, employing an organized planning and development process that explored alternative strategies and vendors in an attempt to improve the systems at a competitive and reasonable price (Exhs. WP-NG-RRP-9; AG-2-25; AG-4-1; AG-4-2; AG-4-4 through AG-4-18; AG-11-14; Tr. 5, at 568-580). We note that among those improvements is the OMS, an IS asset developed and implemented in direct response to a Department Order mandating the Company to improve emergency management procedures related to outages and wires-down response and reporting. D.P.U. 11-85-A/D.P.U. 11-119-A at 151-153.

The record also shows that the IS rental expenses charged by NGSC were allocated to the utility by a cost-effective and non-discriminatory formula (Exhs. WP-NG-RRP-9; DPU-31-16; DPU-31-19; DPU-31-20; AG-1-92; AG-11-2; AG-11-3; AG-11-4). The Department acknowledges that the USFP SAP implementation in 2012 suffered from defects in system construction as well as from an initial lack of understanding by those employees running it (Tr. 5, at 607). The record makes abundantly clear that the NGSC strove to correct those defects at no cost to ratepayers through a $552,228,831 stabilization program subsidized by shareholders (Exhs. NG-MLR-1, at 29; AG-4-10; AG-4-13; AG-4-20; AG-15-11; AG-23-1; Tr. 1, at 41-43, 46-48, 50-57; Tr. 5, at 585-586, 598, 608). What is not clear is whether the Company could have avoided similar problems had NGSC chosen a different system vendor and development path (Exhs. NG-AG-1-6; AG-4-15; NG-11; Tr. 11, at 1595-1600, 1686-1687). Because the utility's actions, based on all that it knew or should have known at the time, were reasonable and prudent, and because the parent company absorbed the stabilization costs, we decline to accept the Attorney General's recommendation of reducing the return on USFP SAP expenses to 3.70 percent.

Regarding the Attorney General's second recommendation, the Department has found a ROE of 9.90 percent is appropriate for the Company (see Section XII.E below). On that basis, the Department finds that application of the Company's proposed capital structure, including a proposed ROE of 10.5 percent, to determine the Company's allocated share of the IS investment would result in Massachusetts ratepayers inappropriately subsidizing the operations of NGSC. To guard against Massachusetts ratepayers inappropriately subsidizing the operations of NGSC, the Department will recalculate the return on NGSC assets using NGSC's capital structure and the 9.90 percent ROE authorized in the instant case. D.P.U. 10-55, at 266-267; D.P.U. 11-43, at 145; D.P.U. 08-27, at 82. Application of the 9.90 percent ROE approved in this order to NGSC's capital structure produces an overall weighted cost of capital of 6.80 percent, and a pretax weighted cost of capital of 10.13 percent (see Exh. NG-RRP-4, at 6 (Rev. 1)). Application of the pretax weighted cost of capital to NGSC's allocation of IT services to the Company yields $19,409,402 in adjusted test year IS rent expense and $8,891,752 in adjusted post-test year IS rent expense (see Exhs. NG-RRP-2, at 15 (Rev. 3)). These amounts when added to the post-test year OMS and EMS operating costs produce a revised IS rent expense of $29,401,991 versus the Company's proposed IS rent expense of $29,732,078 (see Exh. NG-RRP-2, at 15 (Rev. 3); n.201 above). Accordingly, the Department reduces the Company's proposed IS rent expense by $330,087. [221]

e. EHR1 Implementation Costs

The Attorney General's recommendation for eliminating $2.7 million in non-recurring implementation costs associated with EHR1 hinges on an interpretation of this particular project phase as an element of SAP stabilization, for which the associated expenses were charged to the parent company (Exhs. AG-DR-1, at 40-41; AG-4-19; AG-4-20; AG-15-11). Without directly naming the relevant EHR1 project costs as stabilization expenses, the Attorney General nevertheless suggests that they could be construed as such, describing them as SAP systems that were above and beyond NGSC's IS rent expense and with the effect of completing SAP

[221] The $330,087 adjustment consists of (1) a decrease of $195,172 from the Company's proposed adjusted test year amount of $19,604,574 in IS rent, and (2) a decrease of $134,915 from the Company's proposed post-test year amount of $9,026,666 in IS rent (Exh. NG-RRP-2, at 15 (Rev. 3)).

stabilization (Exh. AG-DR-1, at 41).[222] Notably, the expenses involve fees to Deloitte Consulting LLP, the firm that provided much of the stabilization services (Exh. AG-15-11). The Attorney General's challenge to the Company's inclusion of R3-labeled costs booked in the test year exposes a conflict between the Company's claims on stabilization versus non-stabilization costs (Exhs. AG-4-19; AG-4-21; Tr. 5, at 583-592). The Company states that it charged all stabilization costs to the parent company, yet R3 costs that a Company witness clearly identifies as meant for stabilizing the system are included in the revenue request (Exhs. NG-MLR-1, at 29; NG-RRP-2, at 5; WP-NG-RRP-9, at 3, 7; AG-4-19; AG-4-21; Tr. 5, at 585-586). The Company's response that the R3 costs in question included only investments in system enhancements not equivalent to stabilization measures leaves us with a semantics question for which we must look to the record to answer (Exhs. AG-4-10; AG-4-20; AG-23-2).

In the extensive confidential EHR1 project update and review reports submitted to National Grid parent executives, R3 project status reports detail a USFP stabilization phase that ends in September 2014 (Exhs. AG-4-6, Atts. 65 and 72). The Company draws a clear line at September 30, 2014 as the divide separating stabilization and EHR1 implementation projects (Exhs. AG-4-6, Atts. 49, 61 and 65). The post-stabilization USFP EHR1 implementation went live in December 2014 with a second phase rolling out in January 2015, which corroborates with the Company's listing of the various USFP EHR1 components among test year charges challenged by the Attorney General, such as supply chain, finance, IT-delivery, and payroll

[222] In reference to the $2.7 million, the Attorney General witness states, "[H]opefully now that the EHR1 upgrade and enhancements have been implemented, the Company will be past the need to stabilize the USFP SAP systems and these significant SAP implementation expenses will not be an annually recurring event" (Exh. AG-DR-1, at 41).

(Exhs. AG-4-6, Att. 61; AG-4-19). The Company's labeling of these charges as R3 is confusing, even if its witness described them as enhancements (after associating them with stabilization) (Exh. Tr. 5, at 585-591). We accept the Company's documentation of these different project phases and the vendor fees to identify them clearly as post-stabilization enhancements to the EHR1 implementation intended to finish the core SAP system roll-out (Exhs. AG-4-6, Atts. 49, 61, 65 and 72; AG-15-11).[223]

The evidence on the record points to such expenses supporting the core project and not stabilization, with contracts, invoices, and consultant reports describing shortcomings of the Company's base line manual work processes, regulatory reporting, and outdated IT systems requiring large-scale and long-term resolution (Exhs. AG-4-19; AG-15-11; Tr. 5, at 583). The expenses support IS assets fundamental to the routine operation of the Company's business processes related to financial management, regulatory reporting, supply chain, payroll, work order cycles, among other essential functions going forward (Exhs. AG-4-6, Att. 65, 72). The Department views these costs as known and measurable elements of the core project and not among the remedial work the NGSC employed for stabilization. Accordingly, we decline to adopt the Attorney General's recommendation to remove the $2.7 million in EHR1 implementation costs from the cost of service.

f. Savings From EHR1 Implementation

The Attorney General contends that if the Department allows the post-test year EHR1 system plant additions in the determination of NGSC rent expenses, the Company's revenue request should reflect a commensurate savings from IS enhancements designed to improve

[223] The Company provides 58 invoices from consultants helping to develop and implement post-stabilization EHR1 projects (Exh. 15-11).

business processes. The Company maintains that it never anticipated quantifying savings, although it prepared estimates in response to the Attorney General's request for them (Exhs. AG-23-10; AG-23-11). The Company has emphasized the qualitative nature of anticipated savings, and maintains there is no evidence showing realized net savings as a result of the EHR1 implementation, or that net savings are routinely expected from such system enhancements (Exhs. AG-2-25; AG-23-11).

The Department has previously rejected proposed adjustments for savings achieved by projects when the record showed that the savings are speculative or there was uncertainty that savings would be achieved in the rate year. D.P.U. 13-75, at 114; D.P.U. 05-27, at 129-131; D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51. While National Grid identified a five-year savings estimate of $74.35 million during the conceptual phase of the project, the Company ultimately determined that savings were difficult to quantify, and that the benefits of the project were more qualitative in nature through the implementation of reliable and stable IT platforms, enhanced controls, additional data transparency and sustainable technical solutions (Exhs. AG-4-4, Att. 3; AG-23-10; AG-23-11). The Company identifies potential and expected savings in confidential reports to parent company executives, attaching specific dollar amounts to individual project areas (Exh. AG-4-6 , Atts. 61 and 65).[224] It is clear that the Company and its affiliate expect some savings from the IS enhancements, but these are not yet calculable to the degree required by our precedent. Therefore, the Attorney General's proposed adjustment does not meet the

[224] For instance, the Company is tracking 16 quantitative benefits to improvements in supply chain management expected to achieve $3 million in savings annually, and has identified $10 million in estimated annual savings or avoided costs across SAP-related projects (Exh. AG-4-6, Att. 61).

Department's known and measurable standard. D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51. Accordingly, the Department will not adopt the Attorney General's recommendation.

g. Conclusion

As noted above, the Company proposes to recover $29,732,078 in IS expenses incurred during the test year and through the end of the rate year, September 30, 2017 (Exh. NG-RRP-2, at 15 (Rev. 3)). Based on our findings above, the Department concludes that the appropriate level of IS expense is $29,401,991. Accordingly, the Department will reduce the Company's proposed cost of service by $330,087.

P. Environmental Response Costs

1. Introduction

During the test year, National Grid booked $9,120,244 in environmental remediation expenses associated with its electric operations and former manufactured gas plant ("MGP") sites operated by its corporate predecessors (Exh. AG-1-59, Att.).[225] The Company funds its environmental remediation activities through its Environmental Hazardous Waste Fund ("Environmental Response Fund") (Exh. AG-1-59). The Environmental Response Fund was created as part of a settlement agreement ("1993 Settlement") in Massachusetts Electric Company, D.P.U. 93-194 (1993), and is intended to provide for National Grid's environmental remediation activities at both its former MGP sites and electric operation sites where remediation

225 Many of National Grid's corporate predecessors operated as combination gas and electric utilities, and the Company retains responsibilities for environmental liabilities arising from the operation of these entities (Exh. DPU-25-3). The Company has been engaged in remediation activities at 31 electric operations sites and 27 former MGP sites (Exh. DPU-25-8, Att. 6, at 5-6).

of pre-1980 contamination was underway (Exhs. DPU-25-8, Att. 6, at 3 n.1; AG-1-59; 1993 Settlement, § B).[226] The Environmental Response Fund was initially financed through a one-time shareholder contribution of $30 million, and the Company is authorized to increase the fund balance through annual ratepayer contributions indexed to the Gross Domestic Product Implicit Price Deflator ("GDPIPD") as of October 1 of each year (Exhs. DPU-25-3; DPU-25-4; AG-1-59; 1993 Settlement, § B.2).[227]

National Grid booked $4,017,471 in contributions to the Environmental Response Fund during the test year (Exh. NG-RRP-2, at 25 (Rev. 3)). The Company proposes to increase its contributions to $4,168,528, based on the application of an anticipated increase in the GDPIPD to 3.76 percent for the period from the midpoint of the test year (i.e., December 31, 2014) to the midpoint of the rate year (i.e., April 1, 2017) (Exhs. NG-RPP-1, at 36-37; NG-RPP-2, at 25 (Rev. 3)).[228] Consequently, the Company proposes to increase its test year cost of service by $151,057 (Exh. NG-RPP-2, 25 (Rev. 3)).

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226 The 1993 Settlement incorporates amendments by the settling parties, and was stamp approved by the Commission on November 30, 1993. Pursuant to 220 C.M.R. § 1.10(3), the Department incorporates by reference in this proceeding the stamp approved version of the 1993 Settlement.

227 The Company draws from the Environmental Response Fund to provide for remediation activities, including property purchases and claims settlements (Exh. DPU-25-8, Att. 6, at 8). Rental income associated with several MGP sites, third party recoveries, and interest income on the Environmental Response Fund are treated as offsets against the fund (Exh. DPU-25-8, Att. 6, at 2; 1993 Settlement, § 2(c)). Legal and consultant fees associated with defending or prosecuting environmental remediation claims or liabilities are not recovered through the Environmental Response Fund, but are charged instead to various O&M expense accounts (Exh. DPU-25-7).

228 National Grid uses the same method to compute its proposed inflation allowance (see Section VIII.Q below).

2. Positions of the Parties

National Grid contends that it has appropriately calculated its proposed Environmental Response Fund adjustment based on the increase in the GDPIPD from the mid-point of the test year to the mid-point of the rate year applied to its test year fund contribution (Company Brief at 93, citing Exhs. NG-RPP-1, at 36; NG-RPP-2, at 25 (Rev. 3)). Consequently, the Company argues that the Department should accept the proposed adjustment without modification (Company Brief at 93). No other party addressed this issue on brief.

3. Analysis and Findings

The ratemaking treatment of National Grid's environmental remediation expenses was approved as part of the 1993 Settlement. The Department's authority to consider and approve distribution rates through agreed settlements derives from statute. See G.L. c. 164, §§ 76, 93, 94. Rates approved under this broad discretionary authority must conform to the requirements of statute, i.e., they must be "just and reasonable" and "in the public interest" in order to warrant Department approval. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 05-85, at 28 (2005). While the Department neither would nor should disturb matters established by an approved settlement, the public interest requirement of Chapter 164 remains paramount. D.T.E. 05-85, at 29. The Department has no authority to impair or ignore its own statutory authority or obligations, whether by adjudication or by settlement-approval. D.T.E. 05-85, at 29; see also D.T.E. 99-47, at 21 n.20.

National Grid's environmental remediation expenditures involve a wide range of activities, and include consulting fees, contractor costs, regulatory expenses, and legal fees

(Exh. DPU-25-8, Att. 6, at 11-70). No issues have been raised regarding the prudence of the Company's environmental remediation expenditures.[229] Based on the Company's activities and the Department's familiarity with site remediation, particularly remediation efforts related to former MGP sites, we are satisfied that the Company's environmental remediation activities have been prudently incurred and are reasonable in amount. D.P.U. 10-70, at 183-184; Manufactured Gas Plants, D.P.U. 89-161, at 6-29 (1990). Therefore, the Department finds that these expenditures are eligible for recovery through the Environmental Response Fund.[230]

Pursuant to the terms of the 1993 Settlement, National Grid is permitted to increase its annual contribution to the Environmental Response Fund on October 1 of each year, using the GDPIPD (Exh. AG-1-59; 1993 Settlement, § B.2(b)). The annual inflation-indexed increases in the Environmental Response Fund contributions take effect in October of each year, with one-twelfth of the annual contribution credited to the fund each month (Exh. DPU-25-5; 1993 Settlement, § B.2(b)). National Grid, however, applied an inflation factor of 3.76 percent representing inflation between December 31, 2014 (the midpoint of the test year) and April 1, 2017 (the midpoint of the rate year) (Exhs. NG-RRP-2, at 23, 25 (Rev. 3); WP-NG-RRP-16, at 1-4). The Company's calculation incorrectly presumes that the monthly accrual to its

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229 The 1993 Settlement specifies that nothing in the settlement preludes any party from raising issues related to the prudency of National Grid's environmental remediation expenditures (1993 Settlement, § B.3).

230 The Department also has examined the history of contributions to and payments from the Environmental Response Fund (Exh. DPU-25-8, Atts. 1-6). Based on our review, we are satisfied that the Environmental Response Fund remains an appropriate vehicle by which to fund National Grid's environmental remediation activities. In reaching this finding, we recognize that at some point in the future the Company's MGP and pre-1980 electric sites will be fully remediated, thus eliminating the need for an Environmental Response Fund, but also acknowledge that that time has not yet arrived.

Environmental Response Fund increases monthly based on inflation. Because the Company's monthly contributions are determined in October of each year and remain unchanged until the following October, the next inflation-related adjustment to the monthly contribution would not occur until October of 2017, about a year after the issuance of this Order. This error is partially offset by the Company's use of an unadjusted test year contribution that does not fully account for the increased contribution that became effective on October 1, 2014. Based on these considerations, the Department finds that National Grid has incorrectly calculated its Environmental Response Fund contribution.

The Department will calculate a revised contribution based on the most recent inflation rates provided in the record (RR-DPU-10, Att.).[231] The Department finds that a calculation using inflation rates from the midpoint of the period prior to the October 2015 inflation adjustment (i.e., April 30, 2014) and the date of this Order reliably accounts for the inflation-indexed contributions to the Environmental Response Fund that have occurred since the end of the test year. Based on inflation-related data provided in the record, the inflation factor from the midpoint of the test year to the date of this Order is 3.32 percent (see RR-DPU-10, Att. at 3).[232] The Department finds that an inflation factor of 3.32 percent is an appropriate proxy for the annual inflation-indexed adjustments to the Company's contributions to the Environmental Response Fund permitted by the 1993 Settlement.

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231 These rates are current through April 4, 2016 (RR-DPU-10, Att. at 1).

232 The 3.32 percent inflation allowance represents the difference between an interpolated inflation index of 108.23 as of April 30, 2014 and an interpolated inflation index of 111.55 as of September 30, 2016 (see RR-DPU-10, at 2).

Application of an inflation factor of 3.32 percent to the Company's test year end Environmental Remediation Fund balance of $4,017,471 produces an adjusted balance of $4,150,851, representing an increase of $133,380. National Grid has proposed an increase of $151,057. Therefore, the Department reduces the Company's proposed cost of service by $17,677.

Q. Inflation Allowance

1. Introduction

In its initial filing, National Grid proposed an inflation adjustment of $6,311,460 (Exhs. NG-RRP-1, at 35; NG-RRP-2, at 23). The Company then revised its inflation adjustment to $5,312,904 to account for updated expense reporting (Exh. NG-RRP-2, at 23 (Rev. 3)). The Company calculated its inflation allowance using the GDP-PI or "GDP Deflator" as sourced from the U.S. Bureau of Economic Analysis and Moody's Analytics (Exhs. NG-RRP-2, at 23 (Rev. 3); WP-NG-RRP-16 (Rev. 3)). In its initial filing, National Grid calculated the projected change in the GDP-PI from the midpoint of the test year to the midpoint of the rate year as 4.39 percent (Exh. NG-RRP-2, at 23). During the proceedings, the GDP-PI was updated, and the Company revised the inflation factor to 3.76 percent (Exhs. NG-RRP-2, at 23 (Rev. 3); DPU-25-10).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's inflation adjustment should be calculated by applying an inflation factor of 3.76 percent and not 4.39 percent, which was originally proposed at the time of the Company's filing (Attorney General Brief at 27-28).

According to the Attorney General, the lower inflation factor reflects the most recently available GDP-PI information (Attorney General Brief at 27, citing Exh. AG-DJE-1, at 11).

b. Company

National Grid acknowledges the Attorney General's recommendation to apply the most up-to-date inflation factor of 3.76 percent to the residual test year O&M expense, and the Company notes that it has updated its proposed inflation adjustment accordingly (Company Brief at 73-74). However, the Company contends that if it is appropriate to update the revenue requirement to capture changes in the inflation rate with the goal of achieving rates that are representative of actual costs going forward, then it also should be appropriate to capture post-test year changes in the cost of service that are even more significant, such as changes to the Company's IS rent expense (Company Brief at 74).

3. Analysis and Findings

The inflation allowance recognizes that known and inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113; D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21; Commonwealth Electric Company, D.P.U. 956, at 40 (1982). The Department permits utilities to increase their test year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost-containment measures. D.P.U. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71-72.

National Grid calculated its inflation allowance from the midpoint of the test year to the midpoint of the rate year, using GDP-PI information as an inflation measure (Exhs. NG-RRP-2, at 23 (Rev. 3); WP-NG-RRP-16; DPU-25-10). We find this method to be consistent with Department precedent. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. However, we do not accept the Company's proposed inflation factor of 3.76 percent. Instead, the Department concludes that an inflation adjustment of 3.18 percent based on the most recent forecast of GDP-PI from the midpoint of the test year to the midpoint of the rate year, applied to the Company's approved level of residual O&M expense less the Department's adjustments, is proper in this case (RR-DPU-10, Att. at 3).

With respect to cost containment, National Grid provides that the residual O&M expenses subject to inflation include, but are not limited to, items such as transportation, contractors/consultants, employee expenses and materials (Exh. DPU-1-23, at 1). The majority of these categories of O&M expenses are subject to a competitive procurement process (Exh. DPU-23-1, at 1). For example, the Company utilizes a competitive procurement process in procuring contractors and outside services and has adopted a vigorous RFP process for goods and services to ensure that it obtains the best prices available (Exh. DPU-1-23, at 1). Further, the Company has developed unit pricing for its distribution and civil construction services in order to minimize costs (Exh. DPU-1-23, at 2).[233] In addition, transmission line, substation, and larger distribution jobs are competitively bid, with each project undergoing the formal procurement process with proposals and pricing stringently chosen and evaluated (Exh. DPU-1-23, at 2). Finally, the Company has instituted a competitive process for vegetation management contractors, allowing long-term contractors to maintain their existing work on the condition that pricing remains within the pre-determined range (Exh. DPU-23-1, at 2).[234] Based on these considerations, the Department finds that the Company has demonstrated and implemented cost control measures that provide direct ratepayer benefits to warrant the allowance of an inflation adjustment.[235]

If an O&M expense has been adjusted or disallowed for ratemaking purposes, such that the adjusted expense is representative of costs to be incurred in the year following new rates, the test year expense is also removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322-323; D.T.E. 05-27, at 204-205; D.T.E. 02-24/25, at 184-185; Blackstone Gas Company, D.T.E. 01-50, at 19 (2001); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). National Grid has removed test year expenses associated with

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233 Unit prices are established through a complex process of negotiations and are intended to be inclusive of all aspects of the scope of work, such as labor, equipment, fuel, administration, safety, environmental compliance, permitting, travel and delays in order to reduce National Grid's exposure to additional charges (Exh. DPU-1-23, at 2).

234 National Grid notes that other contractors are allowed to maintain 90 percent of their previous year share of work if the Company determines that they have maintained a competitive price and a satisfactory safety and performance record (Exh. DPU-1-23, at 2). National Grid reserves ten percent of work for new vendors with the objective of maintaining a competitive platform (Exh. DPU-1-23, at 2).

235 The Company also provided examples of cost containment measures in other areas, such as with medical and dental expenses (see Section VIII.C above).

various O&M expense items that have either been separately adjusted for ratemaking purposes or are not subject to inflationary pressures, such as salaries and wages, medical and dental expense, and group insurance expense (Exhs. NG-RRP-2, at 23 (Rev. 3); DPU-1-23, at 1). The test year expense associated with these items, totaling $210,633,751, has been removed from National Grid's residual O&M expense calculation (Exh. NG-RRP-2, at 23 (Rev. 3)). In addition, the Department has excluded from the residual O&M expense the test year costs associated with the Company's postage expense. Therefore, the test year expenses associated with this item, totaling $6,595,462 will be removed from National Grid's residual O&M expense calculations, as shown in Table 1.

The Company proposes an inflation adjustment of $5,312,904 (Exh. NG-RRP-2 (Rev-3), at 23). As shown in Table 1, the inflation adjustment for National Grid including Department adjustments, and based on an inflation factor of 3.18 percent, is $4,283,625. Accordingly, the Department will reduce the Company's proposed cost of service by $1,029,279.

Table 1:

Test Year O&M Expense Per Books:		$351,934,387
Less Normalizing Adjustments:		
Salaries & Wages:		
MECO / Nantucket Employees		$64,876,622
Service Company Employees		$73,393,666
Affiliated Company Employees		$3,774,236
Medical and Dental Expense		$18,946,518
Group Insurance Expense		$1,466,588
Employee Thrift Plan - Company Match		$4,792,161
FAS112-ASC712		$78,733
Information Services & Facilities Rent Expense		$28,391,851
Uninsured Claims		$4,082,826
Insurance Premiums		$5,909,663
Regulatory Assessments		$4,920,887
Total for Items Specifically Adjusted or not Eligible for Inflation		$210,633,751
Residual O&M Expenses Subject to Inflation per Company:		$141,300,636
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:		3.76%
Inflation Allowance per Company:		$5,312,904
LESS: Department Adjustments		
Company Adjustments	$210,633,751	
Postage Expense	$6,595,462	
Department Sub-total	$217,229,213	
Residual O&M Expense Subject to Inflation:	$134,705,174	
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	3.18%	
Inflation Allowance per DPU:	$4,283,625	
Reduction to Cost of Service:	$1,029,279	

IX. PROPERTY TAX RECOVERY MECHANISM

A. Introduction

On December 16, 2009, the Massachusetts Appellate Tax Board ("Appellate Tax Board") issued a ruling approving the City of Boston Board of Assessors' change in valuation method for assessing utility property. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (December 16, 2009)). Pursuant to that ruling, the Appellate Tax Board approved Boston's change in method from assessing utility property based on net book value (i.e., original cost less depreciation) to assessing utility property based on weighing net book value equally with "reproduction cost new less depreciation" ("RCNLD").[236] Boston Gas Company appealed the ruling to the Supreme Judicial Court ("SJC"), which upheld the Appellate Tax Board's decision and determined that the valuation method used by Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The SJC then remanded the matter to the Appellate Tax Board for further findings. On April 21, 2011, the Appellate Tax Board issued a final ruling in the matter denying Boston Gas Company's appeal of the property tax valuation of the City of Boston Board of Assessors. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (April 21, 2011).

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236 "Reproduction cost new less depreciation" applies a cost-inflationary factor to age the property in question, with a 20 percent floor on the value of the asset. See Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

The Company states that nine municipalities in its service territory have adopted the RCNLD method (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2; Tr. 6, at 896).[237] According to the Company, property tax increases attributable to the RCNLD method in these nine communities amount to $6,304,272 annually (Exhs. NG-RRP-1, at 90; NG-RRP-7).[238] The Company has appealed the use of RCNLD method to the Appellate Tax Board, and it has sought abatements related to the assessments levied by six of the nine municipalities (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2-4; Tr. 6, at 896).[239] The appeals and abatement requests still are pending (Exh. DPU-22-5, at 2-4). National Grid states that if the appeals are denied and all 235 municipalities in its service territory adopt the RCNLD method, the Company would experience an additional annual increase in property tax expense of $28.3 million (Exhs. NG-RRP-1, at 91; NG-RRP-7, at 2).[240]

B. Company Proposal

The Company proposes a Property Tax Provision ("PTP") tariff to address the aforementioned pending abatements and the potential impact of additional communities adopting

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237 These municipalities are: Billerica, Boston, Everett, Lynn, Somerset, Warwick, Westborough, Westminster, and Worcester (Exh. DPU-22-5, at 2).

238 The Company states that it has not withheld payment of any of the incremental property taxes assessed by any of the nine municipalities (Exh. DPU-22-6).

239 The Company has filed appeals and sought abatements relative to the RCNLD method adopted by the following six communities: Billerica, Everett, Lynn, Somerset, Westborough, and Worcester (Exh. DPU-22-5, at 2-4). National Grid states that the incremental taxes assessed by the City of Boston and the Town of Warwick were nominal and not worth the cost of pursuing (RR-DPU-23). Further, National Grid notes that the Town of Westminster accepted the Company's net book value for the 2015-2016 tax year, so there is no tax dispute (RR-DPU-23).

240 National Grid states that if its pending appeals are denied by the Appellate Tax Board, the Company will pursue relief in court (Exh. DPU-22-10).

the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Specifically, the PTP is designed to refund to customers any abatements received by the Company from municipalities as a result of the Company's challenges to the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199 (proposed M.D.P.U. No. 1282)). Pursuant to the PTP, the Company would allocate the net credit from the abatement to rate classes by applying a rate base allocator derived from the Company's most recent general rate case to determine the amount of the credit allocable to each rate class (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Further, the PTP would permit the Company to recover from customers costs incurred in pursuing the abatements and appeals (Exhs. NG-RRP-1, at 92; NG-PP-23, at 199 (proposed M.D.P.U. No. 1282); DPU-22-7, at 2; DPU-33-9; Tr. 6, at 899-902).[241]

The PTP also would permit the Company to measure and recover any increases in annual property tax expense should additional municipalities adopt the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). The Company proposes to calculate the incremental difference in taxes assessed and to accrue that amount until the end of the calendar year preceding a July 1 filing (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Interest would accrue monthly on unrecovered balances at the customer deposit rate (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). National Grid proposes that on July 1 of each year, the Company would make a filing with the Department to

241 The Company reported legal fees and other costs (e.g., filing fees, independent valuation expert or appraisal fees) associated with the pending appeals of $68,546 (Exhs. DPU-22-5, at 4; DPU-31-9, Atts.). The Company states that if it is unsuccessful in challenging the RCNLD valuation method, it would not seek to recover through the PTP costs related to requests for appeals or abatements (Exhs. DPU-22-8; DPU-31-10). Rather, the Company notes that such costs, to the extent that they are incurred during a test year of a general rate case, would be recovered through base distribution rates resulting from that general rate case (Exh. DPU-31-10).

collect from each rate class the incremental tax and associated carrying costs through a property tax factor ("factor") (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). For each rate class, the factor used to recover the incremental costs would be based on the same rate base allocator used to credit any abatements (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Further, net abatements, if any, would be used to offset the incremental property taxes (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Pursuant to the Company's proposal, the factor would be effective on the following November 1, for a period of twelve months (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). The Company's proposed PTP does not have a specific expiration date (Exh. DPU-22-7, at 3).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Company's proposed PTP should be rejected because it: (1) is speculative in nature; and (2) does not satisfy the Department's long-standing requirements for establishing a new reconciling mechanism (Attorney General Brief at 100; Attorney General Reply Brief at 59). Regarding the first argument, the Attorney General contends that there is no evidence that any other municipality has a pending proposal to adopt the RCNLD (Attorney General Brief at 101; Attorney General Reply Brief at 59). Further, she claims that it is unknown whether the RCNLD method will actually result in an increase in property taxes, that the RCNLD method produced only nominal property tax differences in some communities, and that one municipality reverted back to the net book value method after using the RCNLD method (Attorney General Brief at 101 citing RR-DPU-23; Attorney General Reply Brief at 59). The Attorney General also points out that the Department previously rejected a similar proposal because it was deemed speculative, and she recommends that the Department do the same in this case (Attorney General Brief at 100-101, citing D.P.U. 12-25).

The Attorney General also argues that the Company has failed to show that the proposed PTP meets the requirements of a new reconciling mechanism (Attorney General Brief at 101 citing NSTAR Gas Company Pension, D.T.E. 03-47-A at 17-18 (2003); Worcester Gas Light Company, D.P.U. 11209, at 8-10 (1946)). In particular, the Attorney General argues, while the property tax amounts may be out of the Company's control, National Grid failed to demonstrate that the RCNLD method results in a significant increase in property taxes relative to the annual expense and its earnings (Attorney General Brief at 101, citing RR-DPU-23; Attorney General Reply Brief at 59).

2. PowerOptions

PowerOptions argues that the Company's proposed property tax recovery mechanism should be rejected (PowerOptions Reply Brief at 3, 12). According to PowerOptions, the proposed PTP is "speculative, theoretical and nonconcrete," and such a prospective charge is not just and reasonable or in the best interest of ratepayers (PowerOptions Reply Brief at 12).

3. Company

According to National Grid, its proposal seeks to treat the recovery of any incremental amount of property tax attributable to the RCNLD method as an "exogenous" event, where recovery would be allowed only where the cost is actually incurred (Company Brief at 194; Company Reply Brief at 78). Thus, the Company contends that there is no speculation involved because "[i]f there is no cost, there is no recovery" (Company Brief at 194). Further, the Company maintains that when a municipality adopts the RCNLD valuation method, experience has shown that the increase in property taxes is substantial (Company Brief at 194-195 citing Exh. DPU-22-5; Company Reply Brief at 78). In this regard, although National Grid disagrees with the Attorney General's characterization of the proposal as a new reconciling mechanism, the Company asserts that the PTP is warranted because incremental expenses are beyond the Company's control and significant in amount (Company Brief at 195; Company Reply Brief at 78-79).

D. Analysis and Findings

National Grid seeks a new tariff provision that is designed primarily for the potential impact of additional communities adopting the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). National Grid's proposal is based, in large part, on its concern that other municipalities will adopt the RCNLD method if it is upheld on appeal, which the Company claims will result in a significant annual increase in property tax expense (Exhs. NG-RRP-1, at 90-91; NG-RRP-7). The Company seeks to treat the recovery of any incremental property tax as an exogenous event, while the Attorney General claims that the proposal is akin to a request for a new reconciling mechanism (Company Brief at 194; Company Reply Brief at 78; Attorney General Brief at 101; Attorney General Reply Brief at 59). We need not reach the merits of either argument.

We find that the Company's proposal is premature, speculative, and rests on such a high degree of uncertainty that it fails to warrant establishment of a new, separate charge. See D.P.U. 12-25, at 333. At the close of the record in this case, only nine of the total 235 communities in National Grid's service territory had adopted the RCNLD method (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2; Tr. 6, at 896). Further, the Company considered that the incremental tax increase in two of these communities was so immaterial that it chose not choose to pursue abatements or appeals of the respective municipality's decision to adopt the method (RR-DPU-23). In addition, one municipality that had announced adoption of the RCNLD method used the net book value method for the 2015-2016 tax year, rather than the RCNLD method (RR-DPU-23). Moreover, there is no evidence that any other municipality in the Company's service territory had a pending proposal to adopt the RCNLD.

Additionally, uncertainty exists in the appeals process. At the close of the record, the Company's appeals still were pending (see Exh. DPU-22-5, at 3; Tr. 6, at 897).[242] Further, the Company concedes that if the appeals are denied, it will continue to challenge the RCNLD method in court (Exh. DPU-22-10). Therefore, any final decision on the Company's appeals may be years away.

Based on these considerations, the Department is not persuaded that there is a reasonable certainty that a significant number or, in fact, any additional municipalities will adopt the RCNLD method in the near future.[243] Therefore, we find that the proposed PTP is not warranted

242 Similarly, the record does not disclose any timeline for resolution to the Company's pending abatement requests (see Exh. DPU-22-5, at 3-4).

243 Further, we note that while net book value is a reliable and traditional method for calculating property taxes, we have found that the RCNLD method requires far more intricate calculations and that many smaller municipalities may not have the resources or expertise to easily calculate the new values. D.P.U. 12-25, at 332 n.194. For example, reproduction cost new less depreciation depends on an understanding of current material and labor costs, which can vary widely from region to region. D.P.U. 12-25, at 332 n.194. Smaller municipalities may be forced to hire outside consultants whose fees may exceed the additional tax revenue that a municipality is able to collect through any valuation change. D.P.U. 12-25, at 332 n.194.

at this time.[244] Accordingly, we deny the Company's proposal.[245] Further, we note that in determining the Company's property tax expense (see Section VII.G above), the Department accepted property tax bills from those municipalities that used the RCNLD method of assessment (see Exh. DPU-22-4 & Atts.). Therefore, the higher tax expense for these municipalities is reflected in the Company's representative level of property tax expense.

E. Conclusion

Based on the foregoing, the Department denies the Company's proposal to implement a new tariff to address the pending RCNLD-related abatements and the potential impact of additional communities' adopting the RCNLD method. In its compliance filing, the Company shall revise its tariffs accordingly.

X. ENHANCED VEGETATION MANAGEMENT PILOT

A. Introduction

National Grid's vegetation management program consists of two primary activities – cycle pruning and enhanced hazard tree mitigation ("EHTM") (Exh. DPU-35-1, at 1). Currently, all of the Company's circuits are on a five-year trimming cycle, designed to prune every circuit once every five years (Exh. DPU-35-1, at 1-2). The Company's pruning specifications, which are used by all National Grid contractors, provide for certain minimum distances between all

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244 As provided in Section VIII.G.3 above, the Department will consider, in future base rate proceedings, alternative ratemaking proposals to address property tax changes between base rate cases.

245 To the extent that additional municipalities adopt the RCNLD method and incremental property tax increases to a level that National Grid believes is significant, the Company may petition the Department for appropriate rate making treatment, including a deferral of cost recovery. See, e.g., North Attleboro Gas Company, D.P.U. 93-229 (1994).

vegetation and power lines (Exh. DPU-35-1, at 2).[246] 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 (Exh. DPU-35-1, at 2). Further, the Company notes that it is best-practice to maintain a stable and consistently funded circuit pruning program because it minimizes the risk of public and worker electrocution as well as wild fire events (Exh. DPU-35-1, at 2). In addition, the Company states that consistent cycle pruning also helps maintain service reliability, avoiding potential interruptions from phase-to-phase tree contact (Exh. DPU-35-1, at 2).

National Grid's EHTM program has been in place since 2008 and seeks to identify hazard trees that are diseased, dying, or dead along the Company's circuits and that are susceptible to falling onto power lines and causing power outages and public safety hazards (Tr. 8, at 1308, 1310). The Company states that the ETHM focuses on improving reliability on selected circuits (Exh. DPU-35-1, at 2). National Grid selects circuits for improved reliability based on three-year reliability performance, miles of three-phase bare overhead wire that are most susceptible to tree-related interruptions, tree stocking density, and customer count on the circuit (Exh. DPU-35-1, at 2). The Company reports that over the last three years, it has experienced an average reduction in non-storm customer interruptions of 48 percent on circuits receiving EHTM work when compared to the three-year average prior to the implementation of the EHTM (Exh. DPU-35-1, at 2; Tr. 8, at 1309).

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246 Specifically, the minimum trimming clearance distances are: (1) ten feet below the wire; (2) six feet to the side; and (3) ten feet above the wire in maintained yard areas, or 15 feet above the wire in unmaintained properties (Exh. DPU-35-1, at 2). These clearance distances were established using expected growth rates for vegetation during the five-year cycle (Exh. DPU-35-1, at 2).

B. Analysis and Findings

Neither the Company nor any intervenors made any proposals regarding the Company's vegetation management program. The Department supports preventative actions undertaken by the Company that seek to improve resiliency, reduce storm restoration costs, preserve critical municipal infrastructure during emergency events, and increase circuit reliability during blue sky days and storm events. In this regard, we acknowledge the Company's efforts to improve reliability and safety on its circuits through its cycle pruning program and EHTM (see Exhs. DPU-35-1, at 2; AG-6-2; AG-6-3).[247] We expect that these efforts will continue to produce appreciable results in the context of reducing customer interruptions outside of storm events.

However, the Department has recognized that a more aggressive storm resiliency program may represent a worthwhile step towards strengthening the Company's distribution system, thus mitigating a portion of the physical damage and financial impacts of future storm events, and thereby benefiting ratepayers. D.P.U. 13-90, at 19. As such, the Department will consider the implementation of a pilot program for National Grid with the goal of further reducing tree-related incidents, customer interruptions, and impact on municipalities along worst performing circuits caused by major weather events.[248]

The Department expects that the pilot program would take place over an established period of time (e.g., five years), and would be designed to target trees that are outside of the

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247 With respect to cycle pruning, we note that the Company is considering moving from a five-year cycle to a four-year cycle, thereby further improving reliability and safety (Tr. 8, at 1313).

248 The Department recently approved a storm resiliency pilot program for Fitchburg Gas and Electric Light Company. See D.P.U. 13-90, at 15-23.

scope of the Company's current vegetation management program. In particular, the scope of work would include extensive hazard tree inspections and removals and the clearing of all overhead and under hanging branches (i.e., ground-to-sky clearing) associated with the worst performing three-phase circuits, based upon a consideration of: (1) tree-related field conditions; (2) customer count; (3) miles of each circuit; and (4) presence of scenic roads or other vegetation management restrictions. The scope of work also would take into account critical infrastructure needs for affected cities and towns, and the locations of critical facilities such as police and fire departments, schools, emergency shelters, other critical business centers, and critical electric company infrastructure.

Based on these considerations, the Department directs National Grid to submit, no later than six months from the date of this Order, a filing for Department review that proposes a specific course of action with respect to implementing the above-described pilot program. In addition to providing specific information regarding the timeframe of the program and the scope of work, the Company also shall identify the anticipated costs necessary to implement the pilot program, as well as any recommended cost recovery mechanism. As part of our review of the filing, the Department may seek additional information from the Company.

XI. RECOVERY OF BASIC SERVICE COSTS

A. Introduction

The Company currently recovers, through its basic service rates, supply-related bad debt, as well as certain administrative costs incurred by the Company in arranging basic service that were transferred from base distribution rates to basic service (M.D.P.U. No. 1262;

Exh. NG-PP-23, at 168 (proposed M.D.P.U. No. 1276)). D.P.U. 09-39, at 314.[249] These costs are recovered from customers through a Basic Service Administrative Cost Factor set forth in the Basic Service Adjustment Provision ("BSAP") that is added to the basic service rate for billing purposes (M.D.P.U. No. 1262; Exh. NG-PP-23, at 168 (proposed M.D.P.U. No. 1276)).

National Grid proposes to recover $24,146,875 in test year basic service-related costs through the BSAP (Exh. NG-PP-17, at 1). These costs are segregated into three categories: (1) wholesale costs, which include electric procurement, procurement support, and letter of credit; (2) direct retail costs, which include customer communication, rate change processing, environmental disclosure label, and bad debt expense; and (3) cash working capital (Exh. NG-PP-17, at 2). The costs associated with the letter of credit, bad debt, and cash working capital comprise approximately $23.6 million of the total costs proposed for recovery through the BSAP (Exh. NG-PP-17, at 2). The remaining costs (approximately $580,000) are attributable to administering basic service (Exhs. NG-PP-17, at 2; NG-PP-Rebuttal at 60).[250]

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249 Basic service (formerly referred to as "default service") is electric generation service that is provided by a distribution company to a customer who chooses not to obtain or is unable to obtain electricity from a supplier, or whose supplier fails to provide generation service. The Department changed the name from default service to basic service in Procurement of Default Service Power Supply for Residential and Small Commercial and Industrial Customers, D.T.E. 04-115-A (2005) and adopted that term in Order Adopting Regulations, D.P.U. 07-105 (2008); see also, G.L. c. 164, § 1.

250 In addition to some of the activities identified above, administering basic service also includes activities such as: (1) coordinating and conducting the competitive solicitation; (2) reviewing and selecting bids; (3) negotiating purchase power agreements; (4) calculating and filing rates; and (5) general monitoring of the program along with the costs associated with the procurement and the related retail costs (Exhs. NG-PP-17, at 2; NG-PP-Rebuttal at 60).

B. Positions of the Parties

1. Direct Energy

According to Direct Energy, the proper allocation of costs to basic service is a fundamental issue for electric suppliers that compete against other suppliers and the Company (Direct Energy Brief at 1). Thus, Direct Energy contends that electric suppliers will not be able to compete fully and fairly with basic service until all costs are properly allocated, so that customers served by a competitive supplier are not forced to pay those costs twice (i.e., once in the rate they pay to their supplier and again in the distribution rates that are recovered by the Company as basic service related costs) (Direct Energy Brief at 1). Direct Energy raises several issues with respect to the Company's assignment of costs to the BSAP.

First, Direct Energy argues that the amount of costs assigned to the BSAP for some cost categories is significantly understated (Direct Energy Brief at 7). In particular, Direct Energy argues that of the $24.1 million in costs that National Grid proposes to recover through the BSAP, only $308,000 of direct labor costs are included in the BSAP (Direct Energy Brief at 6-8). Direct Energy asserts that this amount is too small for the size of the Company (Direct Energy Brief at 8-9). In particular, Direct Energy contends that the Company's assignment to the BSAP of costs associated with the legal and regulatory groups fails to reflect the time and effort expended by these individuals on basic service dockets (Direct Energy Brief at 14). As such, Direct Energy asserts that the Company should allocate at least ten percent of all legal and regulatory costs to the BSAP (Direct Energy Brief at 14 & n.5). Similarly, Direct Energy argues that the Company fails to assign to the BSAP a reasonable amount of personnel costs (Direct

Energy Brief at 13-14). In this regard, Direct Energy asserts that at least 2.5 percent of executive costs should be allocated to BSAP (Direct Energy Brief at 14).

Second, Direct Energy argues that additional cost components should be subject to recovery through the BSAP (Direct Energy Brief at 12). In particular, Direct Energy contends that in addition to the costs that National Grid includes for recovery through the BSAP, the Company also should include all direct and indirect wholesale power procurement costs, as opposed to only a portion of these costs; billing system and related costs (e.g., metering) costs; and customer care costs (Direct Energy Brief at 12-14). More specifically, Direct Energy asserts that the Company should allocate to the BCAP at least 57 percent of billing system and related costs, and at least ten percent of customer care costs (Direct Energy Brief at 12-14, citing Exhs. DE-FL-1, at 20-21; NG-RRP-2).

Next, Direct Energy argues that the Company failed to use an appropriate allocated cost of service study, or to properly follow internal cost allocation procedures, in determining the allocation of BSAP costs (Direct Energy Brief at 9-10). According to Direct Energy, the cost allocation study employed in this proceeding failed to allocate a significant amount of properly allocable costs to the BSAP (Direct Energy Brief at 10). Further, Direct Energy asserts that evidence provided by the Company in response to several record requests demonstrates that the Company is inappropriately assigning costs to the BSAP (Direct Energy Brief at 17-21, citing RR-DPU-30; RR-DPU-34; RR-DPU-35).

Further, Direct Energy contends that the Company's assignment of costs to the BSAP is inconsistent with the Department's Standards of Conduct (Direct Energy Brief at 10-12, citing 220 C.M.R. §§ 12.02, 12.03(17)). In this regard, Direct Energy contends that the

Company's basic service business is a competitive energy affiliate of the distribution company (Direct Energy Brief at 10, citing 220 C.M.R. § 12.02). Thus, according to Direct Energy, the Company must fully and accurately assign costs to the basic service business because that business is functionally separate from the distribution business (Direct Energy Brief at 10). Direct Energy argues that the Company has failed to do so and, consequently, the BSAP is under-charged and "heavily subsidized" by distribution operations (Direct Energy Brief at 12). As such, Direct Energy asserts that basic service is not only provided on a competitive basis, it is unfairly competing with other suppliers in the retail market by offering a product that is priced below its true cost (Direct Energy Brief at 12).

Given these purported allocation deficiencies, Direct Energy argues that the Department should require National Grid to provide a "revamped" allocated cost of service study that reasonably allocates to both distribution and basic service the aforementioned costs, as well as any other costs identified by the Company that relate to the provision of both services (Direct Energy Brief at 15). Further, Direct Energy recommends that a revised BSAP charge should be included in the basic service rate and a corresponding amount returned to all distribution customers as a credit to their distribution rates (Direct Energy Brief at 15). Direct Energy asserts that the charge should be reviewed periodically and adjusted as needed, and that such reconciliation would not be disruptive to customers because, in particular, any changes would apply to only a small portion of the bill (Direct Energy Brief at 15-16).

Finally, Direct Energy argues that its proposed BSAP should be implemented in this case and, in addition, the Department should commence a statewide proceeding in order to implement this approach for the remaining electric distribution companies in Massachusetts (Direct Energy

Brief at 15, 24; Direct Energy Reply Brief at 3-4). In this regard, Direct Energy asserts that a state-wide proceeding should only commence after the Department directs National Grid to move forward with a full unbundling of costs (Direct Energy Brief at 24).[251]

2. Company

The Company argues that pursuant to Department precedent, the only costs that should be included in basic service rates are: (1) wholesale-related costs (i.e., the cost of the generation supply, plus ongoing direct procurement-related costs incurred to competitively purchase the supply); and (2) direct retail costs (i.e., commodity-related bad debt, cash working capital, and certain regulatory costs) (Company Brief at 204, citing Provision of Default Service, D.T.E. 02-40-B at 15-18 (2003)). According to the Company, the Department specifically considered, and rejected, the inclusion of indirect retail costs (e.g., customer service and billing) in basic service rates, finding those costs to be related to the provision of distribution service, and not basic service (Company Brief at 204 & n.33, citing D.T.E. 02-40-B at 17). Thus, the Company argues that Direct Energy's recommendations are inconsistent with Department precedent and that no adjustment to the Company's BSAP is warranted (Company Brief at 205-207, citing Exh. DPU-PP-17; D.T.E. 02-40-B at 18; G.L. c. 164, § 1B). Further, the Company asserts that because all electric distribution companies and their customers would be affected by any change in Department policy concerning basic service costs, any consideration of

[251] Direct Energy rejects any notion that its recommendations are (1) inconsistent with Department precedent; (2) unnecessary given the current level of customers receiving competitive supply service in the Company's service area; and (3) unnecessary due to the Company's Purchase Receivables Program (Direct Energy Brief at 21-24, citing Provision of Default Service, D.T.E. 02-40-B (2003); Direct Energy Reply Brief at 1-3). Direct Energy argues that there is no evidence that its recommendations would have any negative impact on the Company's business, pricing, customers, or otherwise (Direct Energy Reply Brief at 4).

implementing Direct Energy's recommendations should be conducted in a generic proceeding in which all stakeholders can participate (Company Brief at 207).

C. Analysis and Findings

1. Introduction

In D.T.E. 02-40-B at 15, the Department recognized that basic service may act as a barrier to the development of competition so long as retail competitive suppliers must recover all of their costs through the prices they charge customers, while distribution companies are able to recover some of their basic service related costs through their distribution rates. Thus, the Department found that basic service rates should include all costs of providing basic service to allow competitive suppliers a fair and reasonable opportunity to compete for basic service customers. D.T.E. 02-40-B at 14.

Specifically, the Department found that because basic service prices collect the supply component of wholesale costs, all supplier-related wholesale costs should be included in basic service prices. D.T.E. 02-40-B at 16. Further, the Department found that procurement-related wholesale costs should be included in basic service rates. D.T.E. 02-40-B at 16. Procurement-related wholesale costs are associated with (1) the design and implementation of the competitive bidding process, including the evaluation of supplier bids and contract negotiations, and (2) the ongoing administration and execution of contracts with suppliers, including accounting activities necessary to track payments made to suppliers. D.T.E. 02-40-B at 16. The Department reasoned that distribution companies incur these costs solely because of their obligation to provide basic service to their customers, and they would not incur these costs if they no longer had the obligation to provide basic service. D.T.E. 02-40-B at 16. Thus, consistent with the policy goals of cost causation, the Department concluded that procurement-related wholesale costs should be included in the calculation of basic service prices. D.T.E. 02-40-B at 16.

The Department also found that direct retail costs should be included in basic service prices, as distribution companies incur these costs strictly on behalf of its basic service customers. D.T.E. 02-40-B at 17. These costs are associated with (1) supply-related bad debt; (2) complying with the Department's basic service regulatory requirements, including required communications with its basic service customers; and (3) compliance with the Massachusetts renewable portfolio standards. D.T.E. 02-40-B at 17. The Department found that similar to wholesale-related costs, a distribution company would not incur these costs if it no longer had the obligation to provide basic service to its customers. D.T.E. 02-40-B at 17.

Finally, the Department distinguished direct retail costs from indirect retail costs, which are associated with services and activities that a distribution company provides to all of its customers alike (i.e., basic service and competitive supply). D.T.E. 02-40-B at 17. In particular, indirect retail costs are associated with the provision of customer service and billing to basic service customers, and the reporting of basic service customers' load to ISO-NE. D.T.E. 02-40-B at 17. The Department found that a distribution company would continue to provide these services, and incur these costs if it no longer had the obligation to provide basic service to its customers. D.T.E. 02-40-B at 17.[252] Thus, the Department determined that these

[252] Viewed from a different perspective, if a basic service customer were to switch to a competitive supplier, the customer would continue to receive the same level of customer service, billing, and load reporting services from the distribution company. D.T.E. 02-40-B at 17.

services are distribution related, rather than basic service related. D.T.E. 02-40-B at 17. Accordingly, the Department concluded that indirect retail costs should not be included in the calculation of basic service prices. D.T.E. 02-40-B at 17-18.

2. Allocation of Basic Service Costs

The Department has reviewed the voluminous record concerning the Company's proposed assignment of costs to the BSAP and Direct Energy's recommendations that we discuss below (Exhs. DE-FL-1, at 17-22; DE-FL-Rebuttal-1, at 4-12; NG-PP-Rebuttal-1, at 57-62; DPU-3-14; DE-1-1; DE-1-2; DE-1-3; DE-2-2; DE-2-3 & Att.; DPU-DE-1-1 through DPU-DE-1-10 (Revised); NG-DE-1-1; Tr. 8, at 1225-1262; Tr. 11, at 1611-1676; NG-5; RR-DPU-30 through RR-DPU-40).

First, we address the Company's proposed assignment of costs to the BSAP. The Company proposes to collect approximately $580,000 through the BSAP, which represents a variety of costs associated with administering basic service (Exh. NG-PP-17). Direct Energy states that this amount translates into about two or three mid-level utility employees to manage the basic service business, which is unreasonable for a company the size of National Grid (Exh. DE-FL-1, at 9-10). According to Direct Energy, it is more reasonable to expect 75 or more employees to administer basic service (Exh. DE-FL-1, at 11). Direct Energy also states that the assignment of these costs is inconsistent with the Company's internal policies and the Department's Standard of Conduct (Exh. DE-FL-1, at 11-16).

Upon review of the record and consideration of the arguments of the parties, we find that National Grid provided persuasive evidence to demonstrate that the costs attributable to administrating basic service are commensurate with the scope of work performed by Company personnel (Exh. NG-PP-17; RR-DPU-31 & Atts.; RR-DPU-32; RR-DPU-33 & Atts.; RR-DPU-34 & Att.; RR-DPU-35 & Att.).[253] Therefore, we are not convinced that the amounts assigned to the BSAP, particularly for legal and regulatory or executive functions, need to be modified.[254] Further, we conclude that Direct Energy's recommended allocation percentages for legal and regulatory costs and executive costs are not appropriate because they are based on questionable assumptions and simplifications (Exh. DE-FL-1, at 20-21). Based on these considerations, we are not persuaded by Direct Energy's arguments that the costs associated with administering basic service are understated.

Next, we address Direct Energy's arguments regarding allocating additional costs to the BSAP. With respect to wholesale procurement costs, Direct Energy argues that National Grid assigns only "a portion" of costs to the BSAP, and fails to indicate what portion it allocated to the BSAP (Direct Energy Brief at 12, citing Exh. DE-2-2; see also Exhs. DE-FL-1, at 17; DE-FL-Rebuttal-1, at 6; DPU-DE-1-2). We disagree with this characterization. Rather, the record shows that National Grid assigns to the BSAP "the portion" attributable to the Company, as opposed to the portion attributable to its affiliate, Narragansett Electric Company (Exh. DE-2-2; see also RR-DPU-30, Att.) (emphasis added). Further, National Grid provided the percentage breakdown between the costs allocated to the Company and its affiliate (RR-DPU-30,

253 For example, we note that a core function associated with administering basic service – the quarterly solicitation process for basic service procurement – is relatively perfunctory in nature, as the Company uses standardized documents that require little if any updating or modifying from one issuance to the next (RR-DPU-32).

254 The Company indicates that executive time associated with basic service functions does not occur on a filing-to-filing basis, but on an annual basis (RR-DPU-40, at 2).

Att.). Thus, we are not persuaded that the Company improperly assigned wholesale procurement costs to the BSAP.

Additionally, Direct Energy recommends an allocation to the BSAP of at least 57 percent of the billing system and related billing costs and 25 percent of customer care costs (Direct Energy Brief at 12, 14; Exh. DE-FL-1, at 17-21). The Department has clearly set forth the types of costs that are included for recovery through the BSAP and those that should be excluded. D.T.E. 02-40-B at 16-18. In particular, indirect retail costs, such as costs "associated with the provision of customer service and billing to [basic] service customers," are not included in the calculation of BSAP prices. D.T.E. 02-40-B at 17. Therefore, based on Department precedent, the Company is not required to allocate billing and billing-related costs and customer care costs to the BSAP.

Given that the Company properly assigned costs to the BSAP, we find that the Company's allocation process was not inconsistent with any of its internal cost allocation policies. Further, we find that the Company's assignment of costs does not violate the Department's Standards of Conduct. In this regard, we are not persuaded that administrating basic service results in an affiliate arrangement with the Company in the context of 220 C.M.R. § 12.00. In particular, we note that electric distribution companies are mandated to provide a basic service offering to customers. G.L. c. 164, § 1B(d). Moreover, basic service is not sold or marketed on a competitive basis, and no profit is earned by the Company.

3. <u>Conclusion</u>

Based on the record and all of the above considerations, we find that the Company's proposed assignment of costs to the BSAP is reasonable and appropriate. As such, we accept

National Grid's proposal to collect $24,146,875 in test year basic service-related costs through the BSAP, and we direct the Company to revise its BSAP tariff accordingly. Regardless of the specific outcome offered here, however, the Department reemphasizes its commitment to developing the competitive supply market in order to offer customers more diverse products, price certainty, and lower prices. In this regard, we recognize the importance of fully identifying and accounting for all of the direct costs incurred in the procurement, administration, and billing of basic service. The Department looks forward to future opportunities to work with suppliers and the supplier industry groups to learn from other markets, adopt best practices, and continue to develop a fair and competitive market in the commonwealth.

XII. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid calculates its overall cost of capital, or WACC, at 8.13 percent, representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exhs. NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev.3)). This rate is based on: (1) a proposed capital structure that consists of 47.93 percent long-term debt, 0.09 percent preferred stock and 51.98 percent common equity; (2) a proposed cost of long-term debt of 5.56 percent; (3) a proposed cost of preferred cost of 4.44 percent; and (4) a proposed ROE of 10.50 percent (Exhs. NG-RBH-1, at 2-3; NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev.3)).

The Attorney General calculates a combined WACC of 7.09 percent developed using an ROE of 8.50 percent (Exh. AG-JRW-1, at 4). Below, we examine: (1) the Company's capital structure and cost of debt; (2) the respective proxy group selections used by the parties in supporting their proposed ROEs; and (3) the appropriate ROE.

B. Capital Structure and Cost of Debt

1. Company Proposal

National Grid relies on a consolidated MECo and Nantucket Electric capital structure (Exhs. NG-RBH-1, at 57-58; NG-RBH-10). As of June 30, 2015, the end of the test year, MECo's capital structure consisted of $797,828,000 in long-term debt, $2,259,000 in preferred stock, and $2,231,018,000 in common equity (Exh. NG-RBH-10). These balances produce a capital structure consisting of 26.32 percent long-term debt, 0.07 percent preferred stock, and 73.6 percent common equity (Exh. NG-RBH-10). As of that same date, Nantucket Electric's capital structure consisted of $51,665,000 in long-term debt and $47,239,000 in common equity (Exh. NG-RBH-10). These balances produce a capital structure consisting of 52.24 percent long-term debt and 47.76 percent common equity (Exh. NG-RBH-10).

National Grid has incorporated proposed changes to the test year-end capitalization balances for both MECo and Nantucket Electric. MECo's proposed long-term debt balance of $1,235,000,000 incorporates the removal of unamortized debt issuance expenses of $2,171,945, as well as the issuance of $435,000,000 in long-term debt associated with the Department's approval in Massachusetts Electric Company, D.P.U. 15-144 (2016) of the issuance of up to $784,000,000 from time to time through March 31, 2018 (Exhs. NG-RBH-1, at 57-58; NG-RBH-10; AG-5-23, Att.; at 3; Tr. 4, at 498-499). MECo's pro forma common equity balance of $1,339,156,000 incorporates the removal of $1,008,243,998 in goodwill and $5,061,963 in accumulated other comprehensive income, along with the infusion of $90,000,000 in equity capital from National Grid's parent company (Exhs. NG-RBH-1, at 57-58; NG-RBH-10; AG-5-23, Att.; Tr. 4, at 498-499). The Company attributes the simultaneous debt issuance and addition of equity capital as part of its effort to keep the Company's capital structure reasonably balanced (Exhs. NG-RBH-10; AG-5-20; Tr. 4, at 498-499).

Nantucket Electric's adjusted long-term debt balance of zero incorporates the removal of $13,300,000 in debt dedicated to the financing of the first undersea cable project, $38,000,000 in debt dedicated to the second undersea cable project, and $360,000 principal amount outstanding as of June 30, 2015, associated with the Massachusetts Development Finance Agency's Electric Utility Revenue Bonds Series 2004 that matured on March 1, 2016 (Exh. NG-RBH-10). Nantucket Electric's adjusted common equity balance of $31,444,000 incorporates the removal of $15,705,556 in goodwill and $89,414 in accumulated other comprehensive income (Exhs. NG-RBH-1, at 58; NG-RBH-10; AG-5-23, Att. at 3).

Based on these adjustments, National Grid proposes a capital structure for the combined MECo and Nantucket Electric operations consisting of $1,235,000,000 in long-term debt, $2,259,000 in preferred stock, and $1,339,156,000 in common equity, for a total capitalization of $2,576,414,000 (Exhs. NG-RBH1, at 3; NG-RBH-10; NG-RRP-8, at 5 (Rev. 3)). These balances produce a capital structure consisting of 47.93 percent long-term debt, 0.09 percent preferred stock, and 51.98 percent common equity (Exhs. NG-RBH1, at 3; NG-RBH-10; NG-RRP-8, at 5 (Rev. 3)). The Company proposes a rate of 5.56 percent for its long-term debt and 4.44 percent for its preferred stock (Exhs. NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev. 3)).

The Attorney General accepted the Company's proposed capital structure and cost of long-term debt, but noted that the Company's proposed capitalization has more equity, and, therefore, less financial risk than the capitalization ratios of the companies in the Attorney

General's proxy group (Exhs. AG-JRW 1, at 27-28; AG-JRW-4, at 1). No other party commented on the Company's capital structure and cost of debt.

2. 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 return on rate base for calculating the appropriate debt service and return on investment for the company to be included in its revenue requirement. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 17-18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986).

The Department normally will accept a company's test year end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure and normally will accept the utility's test year end capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428 429 (1971); D.P.U. 1360, at 26 27; Blackstone Gas Company, D.P.U. 1135, at 4 (1982); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

Regarding the Company's exclusion of $2,171,945 in unamortized debt issuance expenses, no party contested this adjustment. The Department has found that the appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. D.P.U. 92-78, at 91-92; D.P.U. 86-71, at 12. The Company's treatment of unamortized debt issuance costs is consistent with Department precedent. D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52. Therefore, the Department accepts the Company's proposed exclusion of unamortized debt issuance costs.

Regarding the Company's proposed exclusion of $1,029,101,931in goodwill and accumulated other comprehensive income from capitalization, no party contested these adjustments. 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 319-324. In the case of accumulated other comprehensive income, this balance sheet item does not represent "outstanding stock" as used in G.L. c. 164, § 16. Nantucket Electric Company/Massachusetts Electric Company, D.T.E. 04-74, at 21-22 (2004). Therefore, the Department accepts the Company's proposed exclusion of accumulated other comprehensive income from capitalization. D.P.U. 09-39, at 338-339.

Pursuant to the Department's approval in D.P.U. 15-144, the Company closed on the sale of $500,000,000 in 30-year long-term debt on August 5, 2016. (D.P.U. 15-144, Compliance Filing (August 31, 2016). Therefore, the Department finds that the debt issuance represents a known and measurable change to test year-end capitalization. D.P.U. 11-43, at 204-205; D.P.U. 07-71, at 122-123; D.T.E. 05-27, at 272; D.P.U. 84-94, at 52-53. Accordingly, the Department increases the Company's proposed long-term debt balance by

$65,000,000, representing the difference between the proposed inclusion of $435,000,000 approved in D.P.U. 15-155 and the actual issuance of $500,000,000.

National Grid has excluded all of Nantucket Electric's outstanding debt from capitalization (Exh. NG-RBH-10). The $360,000 in MDFA bonds matured on March 1, 2016, and, therefore, they no longer are on Nantucket Electric's balance sheet (Exhs. NG-RBH-10; AG-5-23, Att. at 3). The Department finds that the redemption of the MDFA bonds is a known and measurable change to the Company's test year-end capitalization. D.P.U. 11-43, at 204-205; D.P.U. 10-114, at 289; D.P.U. 90-121, at 157. Turning to the exclusion of $51,300,000 in bonds used to finance Nantucket Electric's underwater cables, the costs of these underwater cables, including financing costs, are being recovered through a separate mechanism. 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 $90,000,000 capital contribution to MECo, the Department finds that National Grid USA capital contribution was intended to fund the Company's operations and to create a more balanced capital structure after the issuance of MECo's long-term debt, planned at that time to be $435,000,000 (Tr. 4, at 498-499). The Department finds that the $90,000,000 capital contribution is a known and measurable change to test year-end capitalization. D.P.U. 15-80/D.P.U. 15-81, at 252; D.P.U. 14-150, at 316-317; D.P.U. 10-70, at 241; D.P.U. 07-71, at 122. Therefore, the Department accepts this proposed adjustment to the Company's capital structure.

Notwithstanding our acceptance here, the Department recognizes that a parent company capital contribution 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. See 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). Although parent holding companies can be a source of financial strength to subsidiaries, capital contributions to a subsidiary outside of the regulatory review process could have consequences where the adjustment to the subsidiary's capital structure results in a higher rate of return. We will, however, continue to examine parent holding company capital contributions for potential adverse rate effects.[255] D.P.U. 10-70, at 242.

Based on the foregoing analysis, the Department shall use a long-term debt balance of $1,300,000,000, a preferred stock balance of $2,259,000, and a common equity balance of $1,339,156,000 to determine National Grid's capital structure. As shown on Schedule 5 of this Order in Section XV below, the use of these balances produces a capital structure consisting of 49.22 percent long-term debt, 0.09 percent preferred stock, and 50.70 percent common equity.

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[255] The capital contributions are not stock issuances as defined in G.L. c. 164, § 14 and, therefore, they are not subject to a determination under G.L. c. 164, § 14 that the contributions were reasonably necessary to accomplish some legitimate purpose in meeting a company's public service obligations. D.P.U. 10-70, at 241-242, citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 395 Mass. 836, 842 (1985), Fitchburg Gas and Electric Light Co. v. Department of Public Utilities, 394 Mass. 671, 678 (1985).

b. Cost of Debt and Preferred Stock

Regarding the Company's proposed costs of long-term debt and preferred stock, no 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. See D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161.

National Grid provided the calculations supporting the cost of its long-term debt and preferred stock (Exh. AG-5-23, Att.). We find that the Company calculated the cost of its 5.90 Percent Senior Notes and preferred stock in a manner consistent with Department precedent. D.T.E. 01-56, at 97-100. For the debt issued pursuant to D.P.U. 15-144, the Company assumed a nominal interest rate of 4.74 percent, and an effective rate of 4.77 percent (Exhs. NG-RBH-12; AG-5-2, Att. at 2). Based on the actual issuance of $500,000,000 in long-term debt associated with D.P.U. 15-144 at a nominal interest rate of 4.004 percent, the Department has recalculated the Company's cost of long-term debt provided in Exhibit AG-5-23 using the $500,000,000 principal balance, the 4.004 percent nominal interest rate, and $136,000 representing the annual amortization of issuance costs. Based on this recalculation, the effective interest rate associated with the debt issued in D.P.U. 15-144 is 4.031 percent,[256] which when combined with Massachusetts Electric's 5.90 Percent Senior Notes, produces an overall

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[256] (($500,000,000 x 4.004 percent) + $136,000) / $500,000,000 = 4.031 percent.

weighted average cost of debt of 5.21 percent.[257] Accordingly, the Department finds that the Company's effective cost of long-term debt is 5.21 percent. The Department also finds that the effective cost of preferred stock is 4.44 percent. We address the Company's proposed 10.50 percent cost of equity in the following sections.

C. Proxy Groups

1. Company Proxy Group

National Grid is a wholly owned subsidiary of National Grid plc. and is not publicly traded (Exh. NG-RBH-1, at 10). Therefore, the Company has no public market for its stock. Accordingly, National Grid presents its ROE analysis using the capitalization and financial statistics of a proxy group of 25 electric companies (Exhs. NG-RBH-1, at 10-15; NG-RBH-11).[258] The Company selected its proxy group from a group of 46 companies classified as "electric utilities" by Value Line Investment Survey ("Value Line") (Exh. NG-RBH-1, at 12). 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 Standard & Poor's Financial Services, LLC ("S&P"); (4) received at least 60 percent of their operating income from regulated electric utility operations over the past three fiscal years;

257 (($800,000,000/$1,300,000,000) x 5.94 percent) + (($500,000,000/$1,300,000,000) x 4.031 percent) = 5.21 percent.

258 The Company removed three companies from its initial group of 25 companies: (1) Dominion Resources, (2) Duke Energy Corp., and (3) Empire District Electric Company (Exhs. NG-RBH-Rebuttal-1, at 18 n.41; Tr. 4, at 501-503; NG-RBH-Rebuttal-9). National Grid explained that these companies entered into significant corporate transactions following National Grid's initial filing, thus deviating from the Company's filing criteria used to select its proxy group (Exhs. NG-RBH-Rebuttal-1, at 18 n.41; Tr. 4, at 501-503; NG-RBH-Rebuttal-9).

(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 currently known to be a party to a merger or other significant transaction (Exh. NG-RBH-1, at 12-13).

2. Attorney General Proxy Groups

In order to develop her rate of return recommendation for the Company, the Attorney General evaluated the return requirements of investors on the common stock of a proxy group of 26 publicly-held electric utility companies (Exhs. AG-JRW-1, at 25; AG-JRW-4, at 1). In selecting those 26 companies, the Attorney General chose companies that: (1) have at least 50 percent of revenues from regulated electric operations as reported by AUS Utilities Report; (2) are listed as an electric utility by Value Line and listed as an electric utility or combination electric and gas utility in AUS Utilities Report; (3) have an investment grade issuer credit rating by Moody's Investors Service, Inc. ("Moody's") and S&P; (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, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and (6) have analysts' five-year earnings per share ("EPS") growth rate forecasts available from Yahoo! Inc. ("Yahoo"), Thomson Reuters First Call ("First Call"), and/or Zacks Investment Research, Inc. ("Zacks") (Exh. AG-JRW-1, at 24-25). On an overall basis, the Attorney General's resulting proxy group (1) receive 82 percent of their revenues from regulated electric operations; (2) have an BBB+ bond rating from S&P,[259] and Baa1 Moody's bond

[259] Bonds rated "BBB+" by S&P exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to

rating;[260] (3) have a current median common equity ratio of 48.8 percent; and (4) have an earned ROE of 9.3 percent (Exhs. AG-JRW-1, at 26; AG-JRW-4, at 1).

The Attorney General developed financial and market data for her proxy group and the Company's proxy group[261] and applied the DCF model to arrive at a common equity recommendation for National Grid of 8.8 percent (Exh. AG-JRW-1, at 61; AG-JRW-10, AG-JRW-12). From this result, the Attorney General deducted 30 basis points to arrive at her recommended ROE of 8.50 percent for National Grid (Exhs. AG-JRW-1, at 63; JRW-10, at 1; AG-JRW-12).[262]

3. Positions of the Parties

a. Attorney General

The Attorney General states that she has evaluated the return requirements of investors on the common stock of both her proxy group and the Company's proxy group of publicly held electric utility distribution companies (Attorney General Brief at 105, citing Exhs. AG-JRW-1,

show relative standing within the major rating categories. S&P Global Ratings available at www.standardandpoors.com.

260 Bonds rated "Baa1" by Moody's are judged to be medium-grade and are subject to moderate credit risk, and thus may possess certain speculative characteristics. The modifier "1" indicates that the obligation ranks in the higher end of its generic rating category. Moody's Investor available at www.moodys.com/Pages/amr002002.aspx.

261 The Attorney General applied her own financial inputs to the Company's proxy group, and removed four companies from the Company's initial proxy group (i.e., Dominion Resources, Duke Energy Corp., Empire District Electric Company, and Southern Company) in light of recent merger and acquisition activities undertaken by these companies (Exhs. AG-JRW-1, at 25; AG-JRW-4; Attorney General Brief at 105).

262 The Attorney General's 30-basis points risk adjustment proposal is based on the difference between the average yields for long-term utility bonds of A3 (the Company's rating) and the lower rating of Baa1 (the average rating of the Company's proxy groups) (Exhs. AG-JRW-1, at 6, 63; AG-JRW-12).

at 22-26; AG-JRW 4).[263] According to the Attorney General, the issuer credit ratings for the Company are A- according to S&P and A3 according to Moody's, while the average issuer credit ratings for both her proxy group and the Company's proxy group are BBB+ and Baa1 according to S&P and Moody's, respectively (Attorney General Brief at 106). The Attorney General contends that National Grid's credit ratings are thus one notch above the S&P and Moody's issuer credit rating of BBB+ and Baa1 assigned to the proxy groups (Attorney General Brief at 105; Tr. 4, at 1564). Therefore, the Attorney General concludes that the Company's investment risk is below that of the proxy groups (see Attorney General Brief at 107).

b. Company

National Grid argues that in determining its ROE, it has used an appropriate proxy group that includes companies that: (1) are based on valid selection criteria; (2) have sufficient financial and operating data to discern the investment risk of the Company versus the comparison group; and (3) derive at least 60 percent of operating income from regulated electric utility operations (Company Brief at 135-136, citing Exhs. NG-RBH-1, at 13-14; AG-5-15; D.P.U. 09-39, at 347-349; D.P.U. 08-35, at 176. In addition, the Company maintains that 13 of its 25 proxy companies have a capital investment cost recovery mechanism in place for at least one operating subsidiary,[264] and that all 25 proxy group companies have a revenue stabilization mechanism in place in at least one jurisdiction (Company Brief at 135-136,

263 The Attorney General argues that when her proxy group is examined in conjunction with the Company's own proxy group, any concern as to her selection of companies is eliminated as an issue (Attorney General Reply Brief at 62-63).

264 National Grid's reference to 25 companies in its proxy group includes the three companies that were subsequently removed because of recent merger activities, as noted above.

citing Exhs. NG-RBH-1, at 41; NG-RBH-9; NG-Rebuttal-1, at 70-71; RR-DPU-19) Further, National Grid notes that the Company's proxy group selected from Value Line consist of companies that have been found comparable by the Department to other Massachusetts electric distribution companies in recent years (Company Brief at 135-136, citing D.P.U. 10-70, at 246-247, 249, 511; D.P.U. 11-01/D.P.U. 11-02, at 379-380, 384; D.P.U. 13-90 at 203, 205, 207).

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. See 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. See 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 the Company 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.

The Department expects diligence by parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the Company. See D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482. The Department expects parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 10-114, at 299; see also D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 10-55, at 480-482.

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 those proxy groups to assist the Department in determining the Company's fair and reasonable cost of equity.

Our acceptance of these groups notwithstanding, we identify several factors that the Department will take into consideration in determining the appropriate 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 the Company's comparability to the proxy groups. Second, some of the holding companies in the proxy groups also are involved in non-regulated businesses beyond energy distribution activities (Exhs. AG-JRW 4, at 1; AG-5-15; AG-JRW-4, at 1; AUS Utilities Reports, passim). All else being equal, these business activities potentially make these companies more risky and 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 309; D.P.U. 07-71, at 135. Therefore, while we accept National Grid's and the Attorney General's proxy groups as a basis for evaluating their ROE proposals, we also will consider the particular characteristics of the Company as compared to members of the proxy groups when determining the appropriate ROE.

D. Return on Equity

1. Company Proposal

In determining its proposed ROE, the Company relied on the discounted cash flow ("DCF") model (including the constant growth and multi stage models), capital asset pricing model ("CAPM"), and the bond yield plus risk premium approach ("risk premium model") (Exhs. NG-RBH 1, at 3; NG-RBH-3; NG-RBH-4; NG-RBH-5; NG-RBH-7; NG-RBH-8). These models were applied to market and financial data developed from its proxy group (Exh. NG-RBH-1, at 10-15). 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 ten percent to 10.50 percent (Exh. NG-RBH-1, at 3).

The Company stated that its proposed ROE takes into account the implementation of decoupling and a capital investment cost recovery mechanism, the Company's particular business risks, and additional qualitative considerations to which the Department precedent has given weight in establishing authorized returns (Exh. NG-RBH-1, at 40-45, 62;

NG-RBH-Rebuttal-1, at 70-71). In this regard, the Company states that its proposed ROE of 10.50 percent is based, in part, on a proxy group of electric distribution companies that, in general, already have implemented revenue stabilization mechanisms (Exh. NG-RBH-1, at 12-14, 40-42). Thus, according to National Grid, any reduction in the ROE because the Company has implemented decoupling or capital-cost recovery mechanisms is a matter of speculation and conjecture and would ignore established legal standards requiring a return commensurate with the return for enterprises with corresponding risks (Exh. NG-RBH-1, at 7-9, 12-14, 40-42, citing Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923) ("Bluefield")).

2. Attorney General Proposal

In determining her proposed ROE, the Attorney General applied the DCF model, including the constant growth model, and the CAPM to her proxy group and she applied the same models to the Company's proxy group (Exhs. AG-JRW-1, at 4, 36-51, 52-61; AG-JRW-10; AG-JRW-11). The Attorney General initially calculated an ROE for National Grid of 8.80 percent based on an evaluation of her CAPM result of 8.10 percent and her DCF results of 8.77 percent and 8.82 percent, and then reduced the 8.80 percent by 30 basis points to recognize what she deemed to be the Company's lower risk profile as compared to the proxy groups, resulting in a proposed ROE of 8.50 percent (Exhs. AG-JRW-1, at 4, 61-63; AG-JRW-10; AG-JRW-11).

On brief, the Attorney General recommends setting the Company's ROE at 7.80 percent, which she considers to be the lowest end of her range of reasonable ROE results (Attorney

General Brief at 125-126, citing Exh. AG-JRW-1, at 61-62).[265] She proposes this ROE to account for what she identifies as a number of Company shortcomings, including its failures to: (1) conform to the Department's explicit instructions regarding the use of a split test year; (2) appropriately account for salvage value, thereby overstating the revenue requirement both in this case and the Company's previous rate case, as well as in the capital tracker mechanism; and (3) remove retired plant from plant in service accounts, resulting in an overstated depreciation expense requirement (Attorney General Brief at 125-126, citing D.T.E. 02-24/25, at 231). Further, the Attorney General notes that interest rates and capital costs remain at historically low levels and are likely to remain so for some time (Attorney General Brief at 123). The Attorney General also points out that authorized ROEs authorized by state regulators for companies under their jurisdiction have declined from 9.94 percent in 2012, to 9.68 percent in 2013, to 9.78 percent in 2014, to 9.58 percent in 2015, and to 9.68 percent in the first quarter of 2016 (Attorney General Reply Brief at 65-66, citing Exh. AG-JRW-Rebuttal-1, at 17-18).

3. Discounted Cash Flow Model

a. Company Proposal

The DCF model is based on the premise that a stock's current price is equal to the present value of the expected future cash flows that investors expect to receive (Exh. NG-RBH-1, at 17). The Company used both a constant growth and a multi-stage DCF model (Exhs. NG-RBH-1, at 17, 24; NG-RBH-3; NG-RBH-4).

[265] The Attorney General's ROE range includes her CAPM result of 7.80 percent (8.10 percent minus the relative risk factor of 30 basis points) and the Company's DCF result of 8.52 (8.82 percent minus the relative risk factor of 30 basis points) (Attorney General Brief at 126, citing Exh. AG-JRW-1, at 61-62).

The constant growth DCF model comprises a forward looking dividend yield component and an expected dividend growth rate into perpetuity as represented by the following formula:

P0 = D1 / (1+k) + D2 / (1+k)2 + ... + D∞ / (1+k)∞.

Where "P0" is today's stock price; "D1," "D2," etc., are all expected future dividends; and "k" is the discount rate (i.e., the investor's required ROE) (Exh. NG-RBH-1, at 17). The Company calculated the dividend yield component based on the current annualized dividends of its proxy group (Exh. NG-RBH-1, at 18). For the expected growth rate, the Company used a consensus of the Zacks, First Call, and Value Line surveys to estimate a long-term earnings growth rate (Exhs. NG-RBH-1, at 22-23; NG-RBH-Rebuttal-2).

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 24). This model employs multiple earnings growth rate and payout rate assumptions (Exh. NG-RBH-1, at 24-29). Earnings growth and payout ratio assumptions change throughout the three stages of this model (Exh. NG-RBH-1, at 24-29). In particular, the Company employed a long-term Gross Domestic Product ("GDP") growth rate of 5.23 percent (Exh. NG-RBH-1, at 29).[266]

The Company's constant growth DCF model as initially filed by the Company produced a cost of equity mean range of 9.08 to 9.27 percent (Exhs. NG-RBH-1, at 23, 63; NG-RBH-3; NG-RBH-4). National's Grid multi-stage DCF model produced a cost of equity range of 9.54 percent to 9.74 percent (Exh. NG-RBH-1, at 63). With data updated through February 29,

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266 The 5.23 percent represents the implied Nominal GDP growth rate that is derived from the following formula: ((1+ Historical Real GDP Growth) * (1+Implied Forward Inflation)) – 1 or ((1+3.25 percent) * (1+1.92 percent)) -1 (Exh. NG-RBH-Rebuttal-1, at 44 n.95). In its rebuttal testimony, the Company revised the Implied Forward Inflation rate to 2.0 percent, resulting in a GDP growth rate of 5.30 percent (Exhs. NG-RBH-Rebuttal-1, at 73; NG-RBH-Rebuttal-3; NG-RBH-Rebuttal-4)

2016, the results of the cost of common equity DCF models were as follows: a constant growth DCF model mean range of 9.13 percent to 9.37 percent and a multi-stage DCF model mean range of 9.47 percent to 9.73 percent (Exhs. NG-RBH-Rebuttal-1, at 75; NG-RBH-Rebuttal-3; NG-RBH-Rebuttal-4).

b. Attorney General Proposal

The Attorney General relies on a constant growth DCF model, reasoning that the public utility business is in the steady state (or constant growth) stage of a three-stage DCF model (Exh. AG-JRW-1, at 38). To determine the cost of equity using her constant growth DCF model, the Attorney General summed the estimated dividend yield and growth rates of her proxy group (Exh. AG-JRW-1, at 51). The Attorney General calculated the DCF dividend yield for the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices based on data supplied by Yahoo (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). Using this method, the median dividend yields for the Attorney General's proxy group range from 3.6 percent to 4.0 percent (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). Within this range, the Attorney General chose the average of the medians of 3.80 percent as the dividend yield for her electric proxy group (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). The corresponding dividend yield for the Company's comparison group as calculated by the Attorney General is 3.85 percent, which is the average of the median dividend yields ranging from 3.7 percent to 4.0 percent (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2).

The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW-1, 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-1, at 41-42).

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, First Call, and Zacks (Exhs. AG-JRW-1, at 42; AG-JRW-10, at 3-6). 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) (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3-6). The DCF projected growth rate for her proxy and the Company's proxy group is 4.75 percent and 5.0 percent, respectively (Exhs. AG-JRW-1, at 50-51; AG-JRW-10, at 1, 3-6). The Attorney General chose the midpoint of this range or 4.875 percent as the DCF growth rate for her proxy group and the Company's proxy group (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1, 3-6)

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-1, at 51; AG-JRW-10, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 8.77 percent and 8.82 percent for her proxy group and the Company's proxy group, respectively (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that her DCF-estimated cost of equity at the lowest end of her range of 7.8 percent appropriately supports her proposed ROE for National Grid (Attorney General Brief at 126, citing D.T.E. 02-24/25 at 231; Attorney General Reply Brief at 60). The Attorney General contends that her proposal takes into account the Company's issues associated with a split test year and depreciation accounting (Attorney General Brief at 126; Attorney General Reply Brief at 60).

The Attorney General asserts that the Department should reject National Grid's DCF analysis for several reasons. First, the Attorney General argues that the Company's analysis has given little weight to its constant growth DCF results, claiming that utility price-earnings ("P/E") ratios have increased, and are now high on both on an absolute and relative level (Attorney General Brief at 110; Attorney General Reply Brief at 62).

Second, the Attorney General contends that the Company's GDP growth rate of 5.23 percent used in its multi-stage DCF model is excessive, 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 109-110, citing Exh. AG-JRW-1, at 68). The Attorney General claims that despite some fluctuations, nominal GDP growth rates have declined over the years and have been in the 3.50 percent to four percent range over the past five years (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Further, she argues that the compounded GDP growth rate of 6.63 percent over the 50 years since the mid-1960s belies a "monotonic and significant" decline in nominal GDP growth rates in recent decades (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Therefore, the Attorney General concludes that a more appropriate nominal GDP growth rate figure for today's economy is in the range of four to five percent (Attorney General Brief at 112-113).

Finally, the Attorney General argues that the Company's DCF analyses are inconsistent in their use of historic versus projected data (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77). In particular, the Attorney General contends that in developing its constant growth DCF analysis, the Company ignored data on historical EPS, dividends per share, and book value per share, relying solely on what she considers to be inflated long-term EPS growth rate projections of Wall Street analysts and Value Line (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63). In addition, the Attorney General claims that, in developing a terminal DCF growth rate for its multi-stage growth DCF analysis, the Company ignored well known, long-term real GDP growth rate forecasts (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63).

ii. Company

National Grid argues that the Attorney General's DCF calculation is subjective and incapable of replication (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 24, 38; Company Reply Brief at 48). In addition, the Company contends that Attorney General's DCF recommendation improperly relies on dividend per share and book value per share growth rates, which it contends are merely derivative of earnings growth (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 34-38).

The Company disputes the Attorney General's claim that it gave insufficient weight to the results of its constant-growth DCF analysis (Company Brief at 142). Instead, the Company claims that what appears to be the issue is the Attorney General's refusal to even consider a multi-stage DCF model in setting a ROE, despite the limiting assumptions underlying the constant-growth DCF model such as the assumption that the P/E ratio stays constant in perpetuity (Company Brief at 142-143, citing Exh. NG-RBH-1, at 24). The Company adds that with P/E ratios for utilities currently at unusually high levels, it is necessary to give consideration to the result of the multi-stage DCF model when determining an appropriate level of ROE (Company Brief at 143, citing Exh. RBH-1-Rebuttal-1, at 23).

In addition, National Grid dismisses the Attorney General's contention that the EPS growth rate estimates relied on by the Company were biased (Company Brief at 143). First, the Company asserts that litigation and new financial regulations in 2003 helped neutralize analysts' conflicts of interest while removing bias in the median forecast errors (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31). Second, the Company maintains that the Department also has noted a lack of pronounced bias in the EPS forecasts for utilities (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31; D.P.U. 13-75, at 302). Third, the Company maintains that regardless of analysts' forecasts, investor expectations are more important when applying the DCF model, and the DCF-estimated ROE must recognize and reflect that it is the EPS growth rate expectations of investors that drive stock prices, even if influenced by analysts' forecasts (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 20-22). Further, the Company notes that the Attorney General conceded that any bias that may exist for utilities is at most in the range of 20 basis points (Company Brief at 143, citing Tr. 14, at 1562).

National Grid also disputes the Attorney General's assertion that the Company's proposed multi-stage DCF growth rate of 5.23 percent, based on GDP growth rate, is inappropriate because such a growth rate does not take into consideration the more recent lower trends in GDP growth or the current forecasts by economists and some federal agencies (Company Brief at 144, citing Attorney General Brief at 111-114). To support its position that its GDP-derived growth rate is appropriate, National Grid notes that the annual nominal GDP growth rate has remained relatively stable since 1990 and was greater than five percent in twelve of the last 26 years (Company Brief at 144).

Further, the Company argues that its proposed long-term growth rate is consistent with other respected economic forecasts on long-term growth (Company Brief at 144). In support of its position, National Grid asserts that a 2010 report issued by McKinsey & Company ("McKinsey Report"), relied upon by the Attorney General in developing her testimony, states that "…long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP" (Company Brief at 144; Company Reply Brief at 52). In the same report, according to the Company, it also is noted that "'[r]eal GDP has averaged 3 to 4 percent over [the] past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent" (Company Brief at 144; Company Reply Brief at 52). Therefore, the Company maintains that its proposed growth rate of 5.23 percent is supported by the McKinsey Report because its selected growth rate represents a combination of historical real GDP growth rate and a corresponding level of expected inflation, and falls within the lower end of the five to seven percent range noted by the McKinsey Report (Company Brief at 144; Company Reply Brief at 52). Further, the Company argues that the Attorney General has not shown that the forecasts she cites are actually relied upon by investors, nor has she explained why she considers economists' near-term interest rate projections are improper while at the same time accepting their long-term real GDP growth rate projections (Company Brief at 144).

Finally, the Company maintains that it has addressed the Attorney General's concerns regarding the appropriate P/E ratio to be used in the DCF analysis by providing an additional set of multi-stage DCF scenarios that calculate the terminal values of the stocks of the companies in the proxy group using a constant average P/E ratio of 18.56 percent (Company Brief at 144-145; Exh. NG-RBH-Rebuttal-4). According to the Company, using a range of multi-stage DCF scenarios with a constant average P/E ratio fully support the Company's proposed 10.50 percent ROE (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-4).

d. Analysis and Findings

In developing their proposed ROEs, both the Company and the Attorney General use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. NG-RBH-1, at 18, 20; AG-JRW-1, at 38). This model has a number of very strict assumptions (e.g., the infinite investment horizon and dividend growth at a constant rate in perpetuity) (Exh. NG-RBH-1, at 20). These assumptions affect the estimates of the cost of equity. D.P.U. 10-114, at 312; D.P.U. 09-39, at 387.

Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358. Specifically, the DCF model includes an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 253; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the results of both the Company's and the Attorney General's DCF models. The Attorney General's DCF model places less emphasis on analyst forecasts of EPS growth rates which, to some extent, compensates for this circularity (see Exh. AG-JRW-1, at 46-47).

The Company and Attorney General use different data sources to estimate the dividend yield and growth rates (Exhs. NG-RBH-1, at 18-19; AG-JRW-1, at 36-46). The Company uses the Bloomberg Professional ("Bloomberg") dividend estimates, adjusting them by one-half of the growth rate, while the Attorney General calculates the dividend yield by applying one-half of the growth rate to a six-month average dividend yield (Exhs. NG-RBH-1, at 19; NG-RBH-3; AG-JRW-1, at 42, 51; AG-JRW-10, at 1). 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 approach over the other. Therefore, we find that both approaches provide a credible basis for evaluating a determination of the Company's allowed ROE.

In addition, the Company and the Attorney General use different growth rates in their respective DCF analyses (Exhs. NG-RBH-1, at 29-30; NG-RBH-4; NG-RBH-Rebuttal 4; AG-JRW-1, at 50-51; AG-JRW-10, at 1). Determining the appropriate long-term growth expectations of investors in a DCF analysis can be difficult and controversial (see Exhs. NG-RBH-1, at 20; AG-JRW-1, at 39). The Company relies on a forward looking growth analysis using EPS, 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 22; NG-RBH-Rebuttal-1, at 38; NG-RBH-Rebuttal-2). Conversely, 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-1, at 42-44). The Attorney General emphasizes dividend growth over earnings growth because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3, 4, 5). The Department has found that investors' heavy reliance on EPS forecasts give credence to the Attorney General's argument that investors are aware of upward biases. D.P.U. 13-75, at 302. Accordingly, the Department will take these biases into consideration in evaluating the Company's DCF analysis.

4. Capital Asset Pricing Model

a. Company Proposal

The Company used the CAPM to estimate the cost of equity for its proxy group (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7). The application of the Company's CAPM resulted in eight individual costs of equity estimates, ranging from 9.46 percent to 11.17 percent (Exhs. NG-RBH-1, at 34, 63; NG-RBH Rebuttal-1, at 76; NG-RBH- Rebuttal-7). National Grid considered these results when determining its proposed ROE (Exhs. NG-RBH-1, at 6; NG-RBH-Rebuttal-7).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. In the CAPM, the required rate of return on common equity 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 31). There are three necessary components to calculate the cost of equity in the CAPM: (1) an expected risk free rate of return; (2) the market risk premium; and (3) the beta, a measure of systematic risk (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7).

The Company used the current and forecasted 30-year Treasury bond yields to arrive at current, near-term, and long-term risk free rates (Exhs. NG-RBH-1, at 32; NG-RBH-5; NG-RBH-6; NG-RBH-7). The CAPM market risk premium is derived from the total return on the overall market minus the risk free rate of return. The Company developed ex ante market risk premiums based on data from both Bloomberg and Value Line by calculating their respective estimated market required returns less the Treasury bond yield (Exhs. NG-RBH 1, at 32-33; NG-RBH-5; NG-RBH-7).

The Company obtained beta coefficients for its proxy group from Bloomberg (0.653) and Value Line (0.75) (Exhs. NG-RBH-1, at 33; NG-RBH-6). Using these beta coefficients in combination with separate Bloomberg and Value Line data and current, near term, and long-term risk free rates, National Grid calculated four Bloomberg market DCF derived CAPM results and four Value Line market DCF derived CAPM results (Exhs. NG-RBH-1, at 34; NG-RBH-7).

b. 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 (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in stocks) (Exhs. AG-JRW-1, at 52; AG-JRW-11, at 1). The Attorney General's CAPM analysis resulted in a cost of equity of 8.10 percent (Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

In her analysis, the Attorney General used the upper bound of the six-month average yield on 30-year Treasury bonds (i.e., four percent) as the risk free rate (Exhs. AG-JRW-1, at 54; AG-JRW-11). The Attorney General then calculated an estimated market risk premium of 5.5 percent, based on the midpoint of a range of market risk premiums of four percent to six percent (Exhs. AG JRW-1, at 59; AG-JRW-11, at 1, 5 6). To calculate the beta coefficient, the Attorney General performed a regression analysis of the returns of the companies in her proxy group against the return of the S&P 500 representing the market, resulting in a median beta coefficient of 0.75 percent (Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1, 3). The Attorney General multiplied the estimated market risk premium of 5.5 percent by the beta coefficients of 0.75 percent to produce an expected equity risk premium of 4.10 percent (see Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1). The risk free rate of four percent added to the expected risk premiums of 4.10 percent results in a cost of equity of 8.10 percent (see Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's CAPM analysis produces results that vastly overstate long-term growth projections (Attorney General Brief at 119). According to the Attorney General, the Company's primary errors are with its use of inflated market risk premiums of 10.05 percent and 10.59 percent (Attorney General Brief at 120). Further, the Attorney General contends that the Company's long-term EPS growth rates of 11.12 percent and 10.80 percent are based on overly optimistic and upwardly biased Wall Street analysts' forecasts (Attorney General Brief at 117-119 citing Exh. AG-JRW-1, at 79-80).

In contrast, the Attorney General maintains that long-term economic, earnings, and dividend growth rates in the United States indicate that historical long-term growth rates are in the five percent to seven percent range (Attorney General Brief at 118). Moreover, the Attorney General asserts that more recent trends suggest lower future economic growth than the long-term historic GDP growth, in the range of four percent to five percent for today's economy, and notes that the projected long-term GDP growth rate forecasts by economists and government agencies are currently in the four percent to five range as well (Attorney General Brief at 118, citing Exh. AG-JRW-1, at 73-75).

Finally, the Attorney General argues that given current low inflation and limited economic growth, the Company's projected earnings growth rates, implied expected stock market returns, and equity risk premiums are not indicative of the realities of the economy (Attorney General Brief at 119, citing Exh. AG-JRW-1, at 80). Based on the above, the Attorney General asserts that the Department should reject the Company's proposed CAPM analysis and recommendations (Attorney General Brief at 120).

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 145, citing Exh. NG-RBH-Rebuttal-1, at 54). Further, the Company contends that the Attorney General's CAPM analyses do not reflect fundamental risk-return relationships (Company Brief at 145).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 168). Using the same analysis as discussed above regarding the DCF model, the Company maintains that recent evidence does not support any upward bias in analysts' forecasts in particular for electric utilities (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-1, at 34).

d. 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. 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; D.P.U. 956, at 54. For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk free rate and has 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 Attorney General's CAPM analysis employs a risk free rate of four percent, using the upper bound of the prior six months' 30-year Treasury bond rates as a proxy (Exh. AG-JRW-1, at 54, 60-61). Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows (Exh. AG-JRW 1, at 21-22). Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk free rate over the long term and, thereby, understate the required ROE. D.P.U. 14-150, at 350; D.P.U. 12-25, at 427; D.P.U. 11 01/D.P.U. 11-02, at 416.

The Company develops a range of risk free rates from 2.68 percent to 3.35 percent, relying on the current 30-year Treasury bond rates as published in Bloomberg, as well as the near- and long-term projected 30-year Treasury bond rates based on interest rate forecasts published in Blue Chip Financial Forecasts (Exhs. NG-RBH-Rebuttal-1, at 75; NG-RBH-Rebuttal-7). The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate. D.P.U. 13-75, at 314.

The Attorney General calculated a market risk premium of 5.5 percent, based on her analysis of numerous surveys of financial professionals, including financial forecasters, chief financial officers, and academics (Exhs. AG-JRW-1, at 59-60; AG-JRW-11, at 1). Alternatively, the Company calculates a revised market risk premium range of 8.46 percent to 11.62 percent based on DCF analyses (Exhs. NG-RBH-Rebuttal-1, at 76; Sch. NG-RBH-Rebuttal-7). 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. D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314.

The Company asserts that because investors rely on financial analysts' forecasts in making investment decisions EPS forecasts are superior to other measures of growth in predicting stock prices (see Exh. NG-RBH-1, at 21). The Department notes that a 2015 survey of over 8,000 academics, financial analysts, and companies estimates a market risk premium of 5.5 percent, which is far lower than the 8.46 percent to 11.62 percent range used in National Grid's analysis (Exhs. NG-RBH-Rebuttal-1, at 76; NG-RBH-Rebuttal-7; AG-JRW-1, at 58;

AG-JRW-11, at 6). Accordingly, the Department places more weight on the Attorney General's approach to developing a market risk premium.

Based on the above considerations, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE. Based on the above considerations, to the limited extent that we rely on CAPM estimates, the Department gives more weight to the Attorney General's proposed CAPM.

5. Risk Premium Model

a. Company Proposal

The risk premium model is based on the concept that investing in common stock is riskier than investing in debt and, therefore, investors require a higher rate of return for equity (Exh. NG-RBH-1, at 34).[267] In the bond yield plus 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 34). Based on data from 1,456 electric utility proceedings between January 1, 1980 and September 30, 2015, the Company derived a risk premium analysis producing a cost of equity range of 10.05 percent to 10.59 percent applicable to its proxy group (Exh. NG-RBH-8).

National Grid calculated the risk premium as the difference between: (1) actual authorized returns using data from 1,456 electric utility rate proceedings between January 1,

267 The equity risk premium is defined as the incremental return that an equity investment provides over the risk-free rate (Exhs. NG-RBH-1, at 34; NG-RBH-8). The risk premium method of determining the cost of equity recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. 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 an estimate of current equity return requirements. D.P.U. 13-75, at 316 n.201.

1980, and September 30, 2015; and (2) the then prevailing long-term Treasury yield (i.e., 30-year bonds) (Exhs. NG-RBH-1, at 35; NG-RBH-8). To account for the forward looking return and interest rates, National Grid calculated the average return period between the filing of this case and the approval of rates, as well as the level of interest rates during the pendency of the proceedings (Exh. NG-RBH-1, at 35). To assess the relationship between the 30-year Treasury yield and the equity risk premium, the Company relied on a statistical analysis that concluded there was a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium (Exhs. NG-RBH-1, at 36-37; NG-RBH-8).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's application of the bond yield plus risk premium model is flawed for three reasons (Attorney General Brief at 120). First, the Attorney General argues that the Company's method produces an inflated measure of the risk premium because it is based on historic authorized ROEs less Treasury yields, and then is applied to projected Treasury yields that always are forecasted to increase (Attorney General Brief at 121). Second, the Attorney General contends that the Company's overall approach improperly uses authorized 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 121, citing Exh. AG-JRW-1, at 83-84). 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 121, citing Exh. AG-JRW-1, at 83-84). Further, the Attorney General argues that the Company's analysis overstates the risk premium because National Grid estimates the risk premium using historical interest rate data, and then applies this data to forecasted interest rates (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 82).

Finally, the Attorney General argues that a comparison of the Company's risk premium results to actual authorized ROEs for electric utility companies confirms the errors in the Company's approach (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). The Attorney General notes that authorized ROEs for electric distribution companies have decreased in recent years, from 10.01 percent in 2012, to 9.8 percent in 2013, to 9.76 percent in 2014, and 9.58 percent in 2015 (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). Moreover, the Attorney General asserts that National Grid's long-term projected Treasury bond yield of 4.9 percent is 200 basis points above current yields and, therefore, is not reasonable (Attorney General Brief at 121, citing Exh. JRW-1, at 82).

ii. Company

National Grid disputes the Attorney General's argument that the Company's bond yield plus risk premium approach gauges regulatory commission behavior rather than investor behavior (Company Brief at 146-147). The Company argues that regulatory decisions reflect market based analyses (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57). Further, the Company contends that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements. For these reasons, the Company asserts that authorized returns are a reasonable measure of investor required returns (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57).

The Company notes that in the past the Department has viewed the risk premium approach as a "supplemental approach" in determining the level of ROE (Company Brief at 147, citing D.P.U. 07-71, at 137). Based on the above, National Grid argues that the Department should at least supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 147).

c. Analysis and Findings

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. See 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.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In the instant case, the Company's risk premium analysis is flawed. First, the Department has recognized the 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. 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 Treasury debt yields provides a better approach. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Company continues to use projected cost of Treasury debt in this model, suggesting that the risk premium approach is forward-looking and, therefore, using the forward-looking approach is appropriate (see Exh. NG-RBH-8). The Department disagrees. The risk premium model is not a forward looking approach, and is, instead, based on current market conditions. See D.P.U. 13-75, at 319; D.P.U.12-25, at 433. Accordingly, the Department finds that current treasury yields are more appropriate than projected yields for use 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.

E. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 692-693 and Hope at 603. 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. See 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 3; NG-RBH-Rebuttal-1, at 77). The Attorney General recommends an ROE of 7.80 percent (Attorney General Brief at 125-126, citing Exh. JRW-1, at 61-62). The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11, cert. denied, 439 U.S. 921 (1978); Boston Gas Company v. Department of Public Utilities, 359

Mass. 292, 305-306 (1971).[268] Thus, in determining an appropriate ROE for National Grid, the Department first evaluates the quantitative factors presented in this case.

In support of its recommended ROE, National Grid has presented quantitative analyses using the DCF model, the CAPM, and a bond yield plus risk premium approach, each incorporating the financial data of its proxy group. 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 (Exh. AG-JRW-4, Panels A and B). The use of empirical analyses in this context is not an exact science. A number of judgments are required in conducting a model based rate of return analysis. 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. D.P.U 18731, at 59. 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.

As discussed above, the evidence demonstrates that each equity cost model used by the Company and the Attorney General suffers from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may not be reliable for the purpose of setting the Company's ROE. For example, we

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268 As noted above, the Attorney General proposes a ROE of 7.80 percent to account for what she identifies as a number of Company shortcomings, including its failures to: (1) conform to the Department's explicit instructions regarding the use of a split test year; (2) appropriately account for salvage value, thereby overstating the revenue requirement both in this case and the Company's previous rate case, as well as in the capital tracker mechanism; and (3) remove retired plant from plant in service accounts, resulting in an overstated depreciation expense requirement (Attorney General Brief at 125-126, citing D.T.E. 02-24/25, at 231). As discussed in Sections III and VIII.E, we decline to adjust the ROE based on these specific recommendations.

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, as well as the inherent limitations in comparing the Company to publicly traded companies. In particular, we find that the Company's DCF analysis overestimates the cost of equity by minimizing the low-outlier estimates. We also find that the Attorney General's DCF model retains some elements of circularity because investor expectations depend upon regulatory decisions.

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 rate of return. 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.[269] D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118;

[269] 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

D.P.U. 18731, at 59; see also 375 Mass. 1, 15. 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. AG-5-15; AG-JRW-4, at 1; AUS Utilities Reports, passim). All else equal, this mix of regulated and unregulated operations would tend to overstate the proxy groups' risk profiles relative to that of the Company. Therefore, in applying this comparability standard, we will consider such risk differentials when weighing the results of the models used to estimate the Company's allowed ROE.

In addition, the Department granted in this Order revisions to National Grid's CIRM (formerly CapEx), which allows the Company to implement an annual rate adjustment to support the net increase in rate base arising from the annual capital additions that the Company makes to upgrade its distribution system (see Section V.D above). National Grid's CIRM, which now accounts for property tax expense, serves to reduce the Company's risks and its investors' return requirement. Although many companies in both proxy groups employ some form of infrastructure recovery mechanism, these infrastructure recovery mechanisms vary among the companies, particularly insofar as the scope of eligible investments and the timing of cost recovery (Exhs. NG-RBH-1, at 40; NG-RBH-9; AG-JRW-4). On the whole, the infrastructure recovery mechanisms for these companies are less comprehensive than the CIRM (Exhs. NG-RBH-9; AG-JRW-4).

> 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.

The Department also recognizes that the Company's decoupling mechanism reduces the variability of the Company's revenues and, accordingly, reduces its risks and its investors' return requirement. See D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although many companies in both proxy groups employ some form of revenue stabilization or decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies and, on the whole, is not as comprehensive as the Company's decoupling mechanism (Exhs. NG-RBH-9; AG-JRW-4).

The Company argues that the pertinent analysis in assessing the impact of decoupling or CIRM on the Company's ROE is not to analyze whether the Company is "less risky" but rather to ascertain whether (1) the effect of the mechanism was to reduce risk below the levels faced by the Company's peers; and (2) investors knowingly reduced their return requirements as a direct consequence of the mechanism (Exh. NG-RBH-1, at 40-42; Company Brief at 139-141). We disagree. While the issue of decoupling and its overall effect on a company's ROE is not a new factor for consideration for the first time in this proceeding, and independent of whether or not investors are keen to compare National Grid's decoupling level of risk vis-à-vis the Company's peers decoupling mechanisms, the fact remains that these mechanisms reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73.

In considering National Grid's allowed ROE, the Department also takes into account the modifications to the Company's storm fund mechanism. In particular, the Department has raised the cost-per-storm threshold, excluded from storm fund eligibility any single storm event with incremental costs that exceed $30 million, and modified the carrying charge component of the storm fund (see Section VI.D). These modifications are intended to prevent a significant storm fund deficit, provide necessary rate stability for customers, more appropriately reflect the costs associated with the storm fund balance, and help ensure that the storm fund works as intended. The Department recognizes that, on balance, these modifications tend to increase the Company's risk associated with the recovery for storm costs when compared to the storm fund approved in D.P.U. 09-39. In addition, the Department takes into account our allowance of National Grid's recovery of its test year balance of protected hardship account receivables (see Section VIII.J.3). In allowing this recovery, the Department provides for the probability of recovery to avoid an impairment of loss by National Grid through a charge to its income statement that could be required by generally accepted accounting principles. We find that this ratemaking treatment of protected hardship account balances reduces the Company's risks.

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[270]

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[270] 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. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 218-222 (company's improper handling of a 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 424-426 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-340 (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); see also D.P.U. 85-266-A/271-A at 172 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

and accepted regulatory practice[271] to consider qualitative factors such as 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 above average or subpar management performance and customer service. See, e.g., 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).

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 9.90 percent is within a reasonable range of rates that will preserve the Company'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

[271] 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); 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); 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).

case.[272] In making these findings, 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.

XIII. 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. 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.

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. 15-80/D.P.U. 15-81, at 295; 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. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption

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[272] In setting this ROE, the Department took into consideration the amount of the storm fund assessment paid by National Grid pursuant to G.L. c. 25, § 18. See Fitchburg Gas and Electric light Company at al. v. Department of Public Utilities, 467 Mass. 768 (2014).

in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.[273]

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. 15-80/D.P.U. 15-81, at 295; 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.

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 allocated cost of service study ("COSS"). 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. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 331; D.P.U. 12-25, at 446; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402-403.

There are four steps to develop an allocated COSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as

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[273] Effective use of energy resources means reducing the total amount of energy consumed without compromising service reliability through the use of more efficient technologies and practices, with clear and timely pricing information, as part of a sustainable energy policy. See An Act Relative to Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298.

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. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446-447; D.P.U. 09-39, at 402-403.

The results of the allocated COSS 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 rates 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. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 403.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an allocated COSS, but also explicitly considers the effect of its 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 also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 403-404. 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). In addition, G.L. c. 164, § 94I ("§ 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.[274] The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 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.

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.

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274 An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, Section 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.

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.

B. Cost Allocation

1. Introduction

National Grid performed an allocated COSS that directly assigns or allocates, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. NG-PP-1, at 9). There are three steps to the Company's allocated COSS.

First, the Company functionalizes costs by its basic function, such as primary distribution, secondary distribution, and customer (Exh. NG-PP-1, at 13-14).[275] The primary distribution function includes costs related to substations, conductors rated 4 kilovolt ("kV") and higher, transmission, and production assets (Exh. NG-PP-1, at 10). The secondary distribution function includes costs related to conductors and other assets that move electricity from the primary system to customers' premises (Exh. NG-PP-1, at 10). The customer function includes costs related to meters, service drops, billing and collection, and any assets and activities that enable the distribution of electricity to the customer (Exh. NG-PP-1, at 10).

Second, the Company classifies each functionalized cost as demand-, energy-, or customer-related according to the system design or operating characteristics that cause them to be incurred (Exh. NG-PP-1, at 9, 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-PP-1, at 16). Energy-related costs vary with the electricity delivered to customers (Exh. NG-PP-1, at 16). Customer-related costs are incurred to attach a customer to

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[275] There are separate functions for primary distribution and secondary distribution because some customers take service at primary voltages (Exh. NG-PP-1, at 14).

the distribution system, to meter and read usage, and to maintain the meter, service drop, and the customer's account (Exh. NG-PP-1, at 15). Customer-related costs are a function of the number of customers the Company serves, are incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile (Exh. NG-PP-1, at 15).

The third step is the allocation of each functionalized and classified cost element to each rate class based on cost-causation principles (Exh. NG-PP-1, at 9, 16).[276] Costs are either directly assigned or allocated to rate classes (Exh. NG-PP-1, at 16).

In allocating costs to rate classes, the Company used external and internal allocators (Exh. NG-PP-1, at 12). External allocators are developed in special studies derived from the Company's accounting, operating, and other records (Exh. NG-PP-1, at 12). 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-PP-1, at 13). Internal allocators are developed within the allocated COSS using a combination of external allocators and other internal allocators (Exh. NG-PP-1, at 13). The Company explains that the internal allocator for property insurance costs 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-PP-1, at 13).

National Grid set its initial revenue requirement target for each rate class to generate equalized rates of return (Exh. NG-PP-1, at 19). This step resulted in an overall average percentage increase to existing base rates of 5.11 percent (Exh. NG-PP-1, at 21). National Grid

[276] Inherent in this third step, as discussed in the Rate Structure section, is the process of identifying an allocator that is most appropriate for costs in each classification within each function.

proposed to limit the rate increases for Rate R-4 and the street lighting rate classes to ten percent of total revenue (Exh. NG-PP-1, at 21). The Company proposed to allocate the revenue shortfall to all other rate classes based on each rate class's share of base distribution revenue (Exh. NG-PP-1, at 21).

2. Positions of the Parties

a. Attorney General

According to the Attorney General, the Company's "unit cost analysis"[277] does not accurately reflect how costs are allocated in the allocated COSS (Exh. AG-SJR-1, at 8, citing Exh. DPU-33-8, at 35). The Attorney General maintains that in the allocated COSS, the Company allocates costs for production plant, power supply expenses, demonstration and selling expense, miscellaneous expenses, and depreciation expense related to production plant using a rate class's energy consumption (Exh. AG-SJR-1, at 9 citing Exh. DPU-33-8, at 14, 16, 18, 22, 24, 25). However, the Attorney General argues that energy consumption does not appear in the Company's unit cost analysis (Exh. AG-SJR-1, at 8). The Attorney General points out that the Company incorrectly states: "the Company has classified all assets and costs as either [d]emand or [c]ustomer. The Company did not classify any asset or cost as [e]nergy" (Exh. AG-SJR-1, at 8, citing Exh. DPU-1-14).[278]

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277 The unitized cost is the cost associated with a utility function divided by the number of units of service for that function (Exh. AG-SJR-1, at 7). It also is referred to as an embedded cost analysis.

278 According to the Attorney General's analysis, the unitized demand-related cost for the residential rate class decreases from $12.90 per kW per month to $12.72 per kW per month, the customer-related costs decreases from $9.42 per month to $9.31 per month, and the unitized energy-related cost is 0.006 cents per kWh (Exh. AG-SJR-1, at 9).

Further, the Attorney General argues that the Company relies on unitized costs to estimate the cost to serve a customer (Exh. AG-SJR-1, at 9). However, the Attorney General contends that the unitized cost for the rate class will likely be different from the actual cost to serve any particular residential customer (Exh. AG-SJR-1, at 9). Therefore, the Attorney General asserts that the average cost to serve a typical customer is fair to all customers, at a given point in time, "because each customer has a fairly equal chance of being served by facilities that are more expensive or less expensive than average" (Exh. AG-SJR-1, 10).[279]

b. Acadia Center

Acadia Center argues that the economic analysis used in an allocated COSS has evolved since the electric industry was created in the United States (Acadia Center Brief at 11). According to Acacia Center, an allocated COSS misses a significant part of the overall picture for system costs (Acadia Center Brief at 11). Specifically, Acadia Center maintains that the traditional allocated COSS is no longer sufficient in rate design because the shift to cost-effective distributed energy resources is not included in the analysis (Acadia Center Brief at 11). Acadia Center contends that the impact on rates from the incorporation of distributed energy resources into a distribution system is a cutting edge topic and is worthy of consideration by the Department, as well as discussion among stakeholders (Acadia Center Brief at 11). Thus,

279 In the Attorney General's example, she explains that if a pole is replaced on a customer's street, the customer is likely paying, in sequence: (1) less than the actual cost of service for a few initial years; (2) equal to the cost of service; and (3) less than the actual cost of service towards the end of the useful life of the pole (Exh. AG-SJR-1, at 10).

Acadia Center asserts that the value of distributed energy resources should be a part of the next evolutionary phase in the economic analysis for ratemaking (Acadia Center Brief at 11).[280]

c. Direct Energy

Direct Energy supports reform to the allocated COSS (Direct Energy Brief at 15). In particular, Direct Energy argues that the Department should require the Company to provide a new allocated COSS that allocates costs to both distribution service and basic service (Direct Energy Brief at 15).[281] Direct Energy recommends that the new allocated COSS be reflected in rates at or close in time to the point at which the Company's proposed rate increases are allowed to take effect (Direct Energy Brief at 15). Further, Direct Energy suggests that the Company should participate in a stakeholder process to review the new allocated COSS, and collectively present an agreed upon allocated COSS to the Department for approval (Direct Energy Brief at 15). Finally, Direct Energy argues that the Company should explain its experiences in allocated COSS reform in a statewide investigation on this issue (Direct Energy Brief at 15).

d. Company

According to the Company, its rate proposals are based on its allocated COSS (Company Brief at 198). National Grid asserts that its allocated COSS directly assigns or allocates each element of its revenue requirement among the rate classes in order to determine the costs of providing service to each rate class (Company Brief at 198, citing Exh. NG-PP-1, at 9). The Company notes that results from its allocated COSS at present rates show that the Company is

280 Acadia Center contends that the benefits include capacity savings, transmission savings, reduced energy prices, and the avoided cost of compliance with greenhouse gas emission requirements (Acadia Center Brief at 11).

281 Direct Energy also raises specific issues related to the Company's recovery of basic service costs in Section XI above.

earning an overall return of 1.18 percent, with class returns varying from negative 7.86 percent to 9.86 percent (Company Brief at 200, citing Exh. NG-PP-2(a)).

3. Analysis and Findings

Pursuant to § 94I, the Department in each base distribution rate proceeding is required 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. The Department finds that National Grid's proposal to cap the rate increase for Rate R-4 and the street lighting rate classes at ten percent of total revenue complies with § 94I (Exhs. NG-PP-4, at 2; NG-PP-1, at 21; DPU-33-8, Att. at 38 (PDF)).

The Company proposed to allocate the revenue increase above the ten percent cap using the uncapped rate classes' share of test year base distribution revenues (i.e., distribution revenues at present rates) (Exhs. NG-PP-1, at 21; NG-PP-4, at 2; DPU-33-8, Att. at 38 (PDF)). The Department's long-standing policy regarding the allocation of class revenue requirements that exceed a cap is that they should be allocated to those rate classes that do not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return. 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. 92-210, at 214. Moreover, the Department recently directed Fitchburg Gas and Electric Light Company to allocate the revenue requirement in excess of the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return instead of test year distribution revenues. D.P.U. 15-80/D.P.U. 15-81, at 302. For these reasons, and to advance the rate goals of fairness and efficiency, the Department directs the Company to allocate the revenue requirement that exceeds the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return.

The Department notes that allocating the revenue requirement that exceeds the ten-percent rate cap based on revenue requirements at equalized rates of return still results in a significant rate increase for Rate R-4 that violates our continuity goal. Consequently, the Department directs the Company to limit the distribution rate increase for Rate R-4 to 200 percent of the overall distribution rate increase, and to allocate the remaining revenue requirement to the uncapped rate classes based on the ratio of their class revenue requirement at equalized rates of return to the sum of the class revenue requirement at equalized rates of return for all uncapped rate classes.[282]

The Department declines to adopt the Attorney General's recommended modifications to the allocated COSS. The Company functionalized all of its costs as primary distribution, secondary distribution, or customer (Exh. NG-PP-1, at 13). Costs are then classified based on system design or operating characteristics (Exh. NG-PP-1, at 15). When classifying the functionalized costs, costs classified as energy-related vary with the electricity sold to or delivered to customers (Exh. NG-PP-1, at 16). All of the assets and costs in the Company's primary and secondary distribution functions are classified as demand-related, and all of the assets and costs in the Company's customer function are classified as customer-related (Exh. NG-PP-1, at 16). Thus, none of the Company's functionalized costs were classified as

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282 The Department makes this directive based on the allocated COSS and revenue requirement in the Company's response to information request DPU-33-8 (Exh. DPU-33-8, Att. at 22). The Department, therefore, directs the Company to apply the 200-percent cap using the allocated COSS and revenue requirements that result from our findings in this Order.

energy-related. In the class allocation step, functionalized and classified costs are then allocated among the rate classes based on causal relationships (Exh. NG-PP-1, at 16). For example, production plant and production O&M were allocated among the rate classes based on each class's test year megawatt-hour deliveries because of the causal relationship (Exh. NG-PP-1, at 16). If customers use more energy, then production plant and O&M costs will increase. Additionally, the Department notes that the Company did not change this classification and allocation method from its allocated COSS that was approved in its last rate case (Exh. DPU-1-7, Att. at 2).

Further, Acadia Center and Direct Energy allege deficiencies in the Company's allocated COSS (Acadia Center Brief at 11; Direct Energy Brief at 15). Having reviewed their arguments, we are not persuaded that the Company's allocated COSS requires any further modification. Therefore, the Department declines to adopt Acadia Center's and Direct Energy's recommendations.[283]

The Department has reviewed National Grid's allocated COSS and, apart from the change to the ten-percent rate cap allocation method and requiring a 200-percent of the overall rate increase cap on the increase to each rate class' distribution revenues, the Department finds that it is reasonable and consistent with Department precedent. D.P.U. 15-80/D.P.U. 15-81, at 303, 309; D.P.U. 13-90, at 240-241; D.P.U. 11-01/D.P.U. 11-02, at 434-437. Accordingly, we accept National Grid's allocated COSS as proposed and with the aforementioned changes. The Department directs the Company to rerun its allocated COSS for submission in its compliance filing to allocate its costs and expenses in excess of the ten-percent cap and 200 percent cap as

[283] In Section XI above, we address in further detail Direct Energy's arguments regarding basic service costs allocated to the Company's Basic Service Adjustment Provision.

approved in this Order. In addition, consistent with D.P.U. 15-80/D.P.U. 15-81, at 339-340, the Company shall update the class-based allocators approved in the instant case for the reconciling mechanism tariffs at the time of each tariff's next scheduled rate change.

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. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 11-10/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372.

2. Company Proposal

National Grid's marginal cost of service study ("MCOSS") follows the same methodology that was used in its last rate case, with minor updates (Exh. NG-HSG-1, at 3).[284] To develop the MCOSS, National Grid first identified the costs for plant additions that are

284 The Company's MCOSS uses peak electricity use plus energy efficiency reductions as the independent variable in its regression analysis. By contrast, the MCOSS approved in D.P.U. 09-39 did not account for energy efficiency reductions (Exh. NG-HSG-1, at 13). Additionally, two un-essential variables included in the MCOSS approved in D.P.U. 09-39 were omitted from the most recent analysis due to their lack of statistical significance (Exh. NG-HSG-1, at 14). Finally, the Company updated the percentages used to allocate primary from secondary system distribution costs (Exh. NG-HSG-1, at 120).

exclusively demand-related (Exhs. NG-HSG-1, at 7; NG-HSG-2).[285] The Company then adjusted these historical costs to 2014 values using the Handy-Whitman Index (Exhs. NG-HSG-1, at 7; NG-HSG-2). Following this adjustment, National Grid multiplied total demand-related plant addition costs by the percentage of total plant addition costs associated with primary distribution service to separate plant addition costs attributable to primary versus secondary distribution systems (Exhs. NG-HSG-1, at 7; NG-HSG-2). Finally, as the MCOSS is only concerned with plant additions that are made to support load growth, the Company removed from primary and secondary distribution plant costs all plant additions made for replacement (Exhs. NG-HSG-1, at 7; NG-HSG-2; NG-HSG-3; NG-NSG-4; NG-HSG-4A).

By regressing primary distribution plant costs on electricity demand,[286] and a number of other explanatory variables, the Company determined that the marginal plant cost per kilowatt ("kW") of demand for the primary distribution sector was $495.29 (Exhs. NG-HSG-6; NG-HSG-7). Using these results,[287] the Company found that the marginal plant cost per kW of demand for the secondary distribution sector was $160.52 (Exhs. NG-HSG-6; NG-HSG-7). The Company then added general plant costs to the marginal

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285 The following variables were considered to be exclusively demand-related: (1) station equipment; (2) overhead conductors; (3) underground conductors; and (4) line transformers (Exhs. NG-HSG-1, at 7; NG-HSG-2).

286 Electricity demand is defined as system peak electricity use plus energy efficiency savings (Exh. NG-HSG-1, at 10).

287 To discern marginal plant cost in the secondary distribution system, the Company calculated the marginal plant cost for the total distribution system ($655.81), and then subtracted from it the marginal plant cost in the secondary distribution system ($495.29). The Company was not able to establish a relationship between marginal plant costs in the secondary distribution system directly because regression analysis did not lead to significant results (Exh. NG-HSG-1, at 11).

capital cost calculations in each sector and multiplied the resulting figures by the economic carrying charge rate (Exhs NG-HSG-1, at 14-15; NG-HSG-8; NG-HSG-8A).[288] The Company adjusted these amounts for O&M expenses, administrative and general expenses, and working capital (Exhs. NG-HSG-1, at 15; NG-HSG-3; NG-HSG-6; NG-HSG-9; NG-HSG-10). It then adjusted the marginal cost estimates for peak demand, 2016 price-levels, and electricity line losses (Exhs. NG-HSG-1, at 17-18; NG-HSG-10; NG-HSG-11).

National Grid calculated an annual marginal cost of $69.65 per kW of demand for the primary distribution system, and an additional $22.77 per kW of demand for the secondary distribution system (Exhs. NG-HSG-1, at 17; NG-HSG-10). After adjusting for electricity line losses, these marginal cost estimates increase to $71.15 per kW for service taken at the primary voltage level and $97.85 per kW for service taken at the secondary voltage level (Exhs. NG-HSG-1, at 17-18; NG-HSG-11).[289] 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 the uncollectable costs for each rate class (Exhs. NG-HSG-1, at 18; NG-HSG-12).

3. Positions of the Parties

a. Attorney General

The Attorney General raises two concerns with the results of the MCOSS (Exh. AG-SJR-1, at 5-7). First, the Attorney General argues that the model used fails to take into

288 The economic carrying charge rate is the percentage of capital cost that provides a return on rate base (Exh. NG-HSG-1, at 15).

289 Service taken at the secondary voltage level includes use of both the primary and secondary distribution system.

account important demand-related costs (Exh. AG-SJR-1, at 6). In this regard, she points specifically to the absence of structures (Account 361), poles (Account 364), and underground conduits (Account 366) in the Company's MCOSS calculation (Exhs. AG-SJR-1, at 6; AG-10-6). According to the Attorney General, including these costs would increase marginal cost by approximately 25 percent, which suggests that the current MCOSS results significantly underestimate marginal cost (Exhs. AG-SJR-1, at 6; AG-10-6).

Second, the Attorney General questions the relevance of MCOSS to the ratemaking process, particularly in designing rates (Exh. AG-SJR-1, at 6-7). In particular, she argues that marginal cost pricing does not allow companies to recover embedded costs, which would prevent companies from collecting the full price of providing its service through rates (Exh. AG-SJR-1, at 6-7). According to the Attorney General, the MCOSS is not particularly useful beyond confirming economic theory on the relationship between marginal cost and average cost (Exh. AG-SJR-1, at 6-7).

b. Company

National Grid reiterates the specifics of its MCOSS on brief (Company Brief at 200-201). The Company submits that its MCOSS is based on the same methodology that was approved in D.P.U. 09-39 (Company Brief at 201).

4. Analysis and Findings

The Department has evaluated National Grid's proposed MCOSS and finds that it incorporates sufficient detail to fully understand the methods used to determine the marginal cost estimates. Consistent with the directives in D.T.E. 05-27, at 322 & n.170, the Company excluded from the MCOSS all production, transmission, and customer costs,[290] as they are irrelevant to the design of distribution rates under the Department's current rate design (Exh. NG-HSG-1, at 2). Further, we conclude that the Company followed all computational guidelines set forth by the Department in developing its MCOSS (Exhs. NG-HSG-1, at 9-14; NG-HSG-6; NG-HSG-7; NG-HSG-8).[291]

The Department has evaluated the Attorney General's concern regarding the Company's decision to omit certain variables, but we find that their omission is not inconsistent with Department directives. The Company's analysis is consistent with the MCOSS approved in D.P.U. 09-39. Further, while more recent MCOSS studies approved by the Department have included structures, poles, and underground conduits in their analyses,[292] we find that the nature of these accounts suggests that they might not be necessary for the purpose of the Company's MCOSS. The record shows that the Company omitted Accounts 361, 364 and 366 from the MCOSS because these plant assets have no load-carrying capacity (Exh. AG-10-6). Depending on the circumstances of the load increase, the Company may or may not be correct in this assertion. However, because the directives set forth in D.T.E. 05-27 seek to eliminate the customer component in the MCOSS, the Department finds it appropriate to treat these assets as non-load-carrying because further investment in these assets would not be required to support a

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290 Costs associated with expanding the Company's customer base.

291 These guidelines include: (1) the use of historical data sets 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.

292 See D.P.U. 13-90, at 241.

marginal increase in load assuming the increase is not the result of an increase in the numbers of customers. Accordingly, based on our review of the Company's MCOSS and the aforementioned considerations, the Department approves the Company's MCOSS.[293]

D. Rate Design

1. Introduction

The Company designed rates to produce a revenue requirement for distribution service of $799.1 million, and proposed to implement its rate design in two phases for Rates R-1, R-2, and G-1 (Exh. NG-PP-1, at 8-9).[294] 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-PP-1, at 23).

2. Phase I

In Phase I, the Company proposed several modifications and increases to the charges under its current rate structure (Exh. NG-PP-1, at 8). National Grid proposed a flat rate structure for Rates R-1, R-2, and G-1, and the elimination of its current inclining block rate design implemented in its last base distribution rate case (Exh. NG-PP-1, at 50, 66, 69). Further, the Company proposes to eliminate Rate S-20 (street & area lighting, Company-owned equipment, HPS conversion) and Rate E (limited residential electric space heating) (Exhs. NG-PP-1, at 22;

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293 We acknowledge the Attorney General's position regarding the relevance of the MCOSS in the context of designing rates, and we recognize that rate design is intended to recover embedded costs, which are typically higher than marginal costs. The Department's findings with respect to the Company's rate design proposals are set forth in greater detail below.

294 In Phase II, the Company has not proposed any changes to rate structure for Rates R-4, G-2, G-3, or the street lighting rate classes (Exh. NG-PP-1, at 64).

DPU-23-4). Additionally, National Grid proposes a new light emitting diode ("LED")[295] option on Rate S-1 (Company-owned street lighting rate) (Exhs. NG-PP-1, at 22; NG-PP-23, at 24, 87 (proposed M.D.P.U. Nos. 1270 (MECo) and 528 (Nantucket Electric))). For Rate G-3, the Company proposes to remove the volumetric rate and bill customers only a customer charge and demand charge (Exh. NG-PP-1, at 57-58).

Finally, for both Rates G-2 and G-3, the Company proposes to revise the definition of billing demand to include a demand ratchet (Exh. NG-PP-1, at 22, 54). Currently, a Rate G-2 or G-3 customer's billing demand is based upon the customer's maximum metered use during a 15-minute interval during all hours (Rate G-2) or peak hours (Rate G-3) of the billing month (Exh. NG-PP-1, at 56). A demand ratchet modifies the definition of a Rate G-2 or G-3 customer's billing demand to be the greater of: (1) the maximum metered kW; (2) 90 percent of the maximum metered kilovolt-amperes ("kVA"); or (3) a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months (Exh. NG-PP-1, at 56).

3. Phase II - Tiered Customer Charges

For residential and small commercial customers and industrial ("C&I") (i.e., Rates R-1, R-2, and G-1), the Company proposes to shift cost recovery from the kWh charge to tiered customer charges in Phase II of its proposal (Exh. NG-PP-1, at 8, 22). The Company's proposed Phase II rate design is to take effect no earlier than six months after the implementation of Phase I rates, or approximately May 1, 2017 (Exhs. NG-PP-1, at 8; DPU-9-16).

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[295] LED lights are energy efficient, have long lives, and do not contain hazardous chemicals like the mercury that is contained in mercury-vapor lamps. See D.P.U. 11-01/D.P.U. 11-02, at 471.

National Grid's Phase II rate design proposal implements a four-tiered customer charge (Exh. NG-PP-1, at 32). The Company defines each tier by a kWh range, or a proxy for customer size, intended to represent a customer's monthly maximum demand (Exh. NG-PP-1, at 32, 36, 41). The Company proposes to assign a customer to a tier based on his or her maximum kWh usage in a billing month, over the last twelve billing months (Exh. NG-PP-1, at 36, 41). The customer charge for each succeeding tier is higher relative to the prior tier, and the tiers are intended to approximate a rate design with a customer charge and a demand charge (Exhs. NG-PP-1, at 35-36; NG-PP-Rebuttal-1, at 11). The Company proposes to recover most, if not all, of the customer-related revenue requirement and a portion of the demand-related revenue requirement based upon the billing determinants of the applicably-sized customers in each tier (Exh. NG-PP-1, at 33).

The proposed tiers and customer charges for Rates R-1 and R-2 are listed below.

Phase II

Tier	**kWh**	**Charge per Month**
Tier 1	0 – 250	$6.00
Tier 2	251 – 600	$9.00
Tier 3	601 – 1,200	$15.00
Tier 4	> 1,200	$20.00

(Exh. NG-PP-1, at 65).

According to the Company's billing data, approximately twelve percent of residential customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 66). Approximately 27 percent of the residential customer bills will fall into the second tier (Exh. NG-PP-1, at 66). The remaining 61 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 66). The Company proposes to recover approximately 42 percent of the Rate R-1 and R-2 revenue requirement through the four proposed customer charges, compared to 17 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 68).

The proposed tiers and customer charges for Rate G-1 are listed below.

Phase II

Tier	**kWh**	**Charge per Month**
Tier 1	0 – 75	$10.00
Tier 2	75 – 500	$11.00
Tier 3	501 – 2,000	$15.00
Tier 4	> 2,000	$30.00

(Exh. NG-PP-1, at 69).

According to the Company's billing data, approximately 15 percent of G-1 customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 69). Approximately 29 percent of customer bills will fall into the second tier (Exh. NG-PP-1, at 69). The remaining 56 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 69). The Company proposed to recover approximately 31 percent of the Rate G-1 revenue requirement through the four proposed customer charges, compared to 18 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 70).

4. Attorney General's Seasonal Rate Design Proposal

The Attorney General proposes an alternative rate design for Rates R-1 and R-2 with a higher volumetric rate during July, August, and September (Exh. AG-SJR-1, at 29). She proposes a $5.50 customer charge, a base distribution rate of $0.04180 per kWh during October through June, and a base distribution rate of $0.04809 during July through September (Exhs. AG-SJR-1, at 29; AG-SJR-11). This rate design was based on the Attorney General's comparison of the summer energy use and the customer's contribution to class non-coincident peak demand, information that was provided by the Company (Exh. AG-SJR-1, at 17). The

Attorney General states that she put forth this proposal as a better proxy for demand related-costs than was instituted in either the Company's Phase I or Phase II rate design proposals (Exh. AG-SJR-1, at 18).

5. Positions of the Parties

a. Attorney General

i. Phase I

The Attorney General argues that the Company's proposed Phase I rate design is not as efficient or fair as it should be (Attorney General Brief at 130). For example, according to the Attorney General's analysis, revenues collected from a customer would only increase by 57 cents for each dollar increase in the cost of serving the customer (Attorney General Brief at 129-130, citing Exh. AG-SJR-1, at 22). Moreover, the Attorney General contends that low-use customers will experience higher bill increases (i.e., a 28.6-percent increase for consumption less than 600 kWh) than high-use customers (i.e., 11.3-percent increase for consumption greater than 600 kWh) (Attorney General Brief at 129, citing Exh. AG-SJR-1, at 12). Therefore, the Attorney General asserts that the Company's Phase I rate design would collect too much revenue from low-use customers and not enough revenues from high-use customers (Attorney General Brief at 129-130).

ii. Phase II – Tiered Customer Charges

The Attorney General argues that the Company's tiered customer charge proposal is "radically" different than any other rate design in effect in Massachusetts or elsewhere in the United States (Attorney General Brief at 131, citing Exh. DPU-12-2; Attorney General Reply Brief at 71-72). According to the Attorney General, the Company's tiered customer charge proposal does a poor job of reflecting the cost of serving different customers and results in unfavorable bill impacts compared to alternative rate designs (Attorney General Brief at 134; Attorney General Reply Brief at 71-72, 76). Moreover, the Attorney General contends that tiered customer charges are inconsistent with the Department's rate design principles and goals (Attorney General Brief at 127). According to the Attorney General, when developing rates, the Department must balance rate design principles, giving the appropriate weight to each principle based on the importance of different policy goals (Attorney General Brief at 128). As discussed in greater detail below, the Attorney General argues that the Company's Phase II rate design proposal: (1) results in arbitrary and incorrect rate changes, violating the rate design goal of fairness; (2) results in large bill impacts, violating the rate design goal of continuity; and (3) fails to recover the appropriate costs from high-use customers, violating the rate design goal of efficiency (Attorney General Brief at 127,132). Therefore, the Attorney General asserts that the Department should reject the Company's tiered customer charge proposal (Attorney General Reply Brief at 76).

(A) Fairness

According to the Attorney General, the Company's tiered customer charge proposal violates the rate design principle of fairness (Attorney General Brief at 133). More specifically, the Attorney General asserts that customers will experience: (1) arbitrary rate changes based on the day of week when the meter is read; and (2) the potential for incorrect rate changes from estimated billing procedures (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25). As an example, the Attorney General notes that a customer may use more electricity by doing laundry and watching the television at the same time during off-peak, low demand weekend hours, and she contends that it is unfair for a customer to be charged a higher tiered customer charge for a year based on one weekend in one billing cycle (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).[296] The Attorney General claims that the Company acknowledged this issue but did not modify its proposal (Attorney General Brief at 132, citing Exh. AG-12-9; AG-12-11). Moreover, the Attorney General assert that the Company did not address the concern that estimated meter reads could place customers into a higher tier customer charge for a year (Attorney General Brief at 133, citing Exh. AG-12-10).

(B) Continuity

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of rate continuity (Attorney General Brief at 132). Based on the Attorney General's analysis of approximately 854,000 customers on Rates R-1 and R-2, she calculated bill impacts ranging from a 14-percent decrease to a 182-percent increase (Attorney General Brief at 133, citing Exhs. AG-SRJ-1, at 27-28; AG-SJR-10; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 27-28). Therefore, the Attorney General contends that the Company's Phase II proposal results in extraordinary and unacceptable impacts on customers'

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296 The Attorney General cites to testimony from her witness to support her argument:

> Some customers use substantially more electricity on the weekends when they (and their children) are home from work or school, doing laundry, watching the television more hours per day, and heating or cooling the home to a more comfortable temperature all day. If a billing period has five Saturdays and Sundays instead of four, such a customer could be placed into a higher tier just because of the quirks of the billing cycle.

(Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).

bills (Attorney General Brief at 132; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29).

(C) Efficiency

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of efficiency (Attorney General Brief at 132). According to the Attorney General, the Company's proposal does not better reflect the cost of serving customers because a customer's bill will increase by only 54.1 cents for each dollar increase in costs (Attorney General Brief at 134, citing Exhs. AG-SJR-1, at 23; AG-SJR-8; Attorney General Reply Brief 72, citing Exh. AG-SJR-1, at 23). Moreover, she contends that the tiered customer charges fail to recover the appropriate costs from high-use customers (Attorney General Brief at 132). Therefore, the Attorney General claims that the Company has not supported its claim that tiered customer charges are more reflective of cost-based rates (Attorney General Reply Brief at 72).

Moreover, the Attorney General argues that the Company has not supported its position that the Phase II rate design proposal is a reasonable proxy for a residential rate structure, where the customer charge is designed to recover customer-related costs and a demand charge recovers capacity-related costs (Attorney General Reply Brief at 72, citing Company Brief at 217). In this regard, the Attorney General maintains that there is a weak correlation between a residential customer's annual energy consumption and its contribution to the class's non-coincident peak demand and its contribution to coincident peak demand (Attorney General Brief at 130; Attorney General Reply Brief at 72). As such, she claims that the Phase II rate design is statistically different than a rate design that includes an actual demand charge for residential customers

(Attorney General Brief at 130; Attorney General Reply Brief at 72-73). Further, according to the Attorney General's analysis of more than 12,000 residential customers with demand meters, the Company's Phase II proposal showed the worst results as a proxy demand charge rate compared to rate design alternatives (Attorney General Reply Brief at 72, <u>citing</u> Exh. AG-SJR-1, at 15-17). Therefore, the Attorney General asserts that the Company's tiered customer charge proposal does not meet the rate design principle of efficiency (Attorney General Brief at 129-130).

iii. <u>Seasonal Rate Design</u>

The Attorney General argues that her seasonal rate design proposal is consistent with the Department's rate design goals because it avoids extreme bill impacts, sends appropriate price signal, and is easy for customers to understand (Attorney General Brief at 134-135, 138). According to the Attorney General, a seasonal rate design sets cost-based rates and balances cost causation concerns with customer bill impacts (Attorney General Brief at 134-135; Attorney General Reply Brief at 72).

The Attorney General argues that with a residential customer charge of $5.50 per month and base distribution rates 15 percent higher during the months of July through September, as she recommends, the Company's residential rate design will be closer to the cost of service (Attorney General Brief at 136, <u>citing</u> Exh. AG-SJR-1, at 29). For example, the Attorney General asserts that her proposed seasonal rate design would recover 57.4 cents for each dollar of the cost increase, compared to National Grid's Phase I and Phase II rate design proposals, which would recover 57 cents per dollar increase and 54.1 cents per dollar increase, respectively (Attorney General Brief at 136, <u>citing</u> Exhs. AG-SJR-1, at 30; AG-SJR-12).

Moreover, the Attorney General argues that the 15-percent differential between summer and winter rates is less than the full difference in the cost of serving in these periods, but represents a transitional measure that takes into account customer bill impacts for all customers, including those with largely seasonal consumption (Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29). According to the Attorney General, her proposed seasonal rate design results in bill increases of 10 percent to 38 percent, compared to the Company's tiered customer charge proposal, which she claims results in bill impacts of negative 14 percent to 182 percent (Attorney General Brief at 137, citing Exh. SJR-1, at 30). Thus, the Attorney General asserts that her proposal results in bill impacts that are more reasonable than the Company's (Attorney General Reply Brief at 75, 76).

The Attorney General rejects any notion that there is no cost basis for the 15-percent differential between summer and winter base distribution rates, and she notes that the Company's own cost of service supports her recommendation (Attorney General Reply Brief at 73-74, citing Company Brief at 224). In particular, the Attorney General notes that the Company concluded from its marginal cost of service study that summer coincident peak demand was the major driver of demand-related costs on the Company's system (Attorney General Reply Brief at 74, citing Tr. 8, at 1284-1286). Moreover, the Attorney General contends that even if the Company's system peaks in the winter in a hypothetical year, the system still would be designed to serve summer peaking loads because "one of the critical factors in designing an electric distribution system is the heat associated with peak loads" and the higher ambient temperatures in the summer (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). The Attorney General reasons that the carrying capacity of distribution system equipment is higher in the winter than in the summer because of the temperature (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). Further, the Attorney General maintains that the Company did not rebut this evidence (Attorney General Reply Brief at 74).

Additionally, the Attorney General argues that system and class peak demands are the primary drivers of demand costs in the allocated COSS (Attorney General Brief at 135). According to the Attorney General's analysis, she claims that there is a stronger correlation between peak-season energy consumption (versus annual energy use) and peak demand because of the significant relationship between a residential customer's energy consumption during the months of July through September and the contribution to system and class peak demands (Attorney General Brief at 135). For example, the Attorney General contends that 48 percent of the variation in customer's contribution to the peak demand is explained by energy consumption during July through September (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Conversely, she claims that only 27 percent of the variation in peak demand is explained by annual energy use (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Therefore, the Attorney General asserts that residential customers' consumption during July through September is a better proxy for demand than annual consumption, and, therefore, her proposed seasonal rate design serves as a better proxy for a demand-charge rate because it produces bills that are most similar to demand-based bills (Attorney General Brief at 135, citing Exh. AG-SJR-1, at 19; Attorney General Reply Brief at 73, citing Exh. AG-SJR-Rebuttal-1, at 7-8; Attorney General Reply Brief at 76). Moreover, the Attorney General claims that she and the Company agree that summer peak demands are a critically important factor in determining the cost to serve residential customers (Attorney

General Reply Brief at 74). Thus, she asserts that this fact, and her statistical analyses, prove that the seasonal rate design proposal has merit and the Department should adopt it (Attorney General Reply Brief at 75, 76).

In sum, the Attorney General argues that a seasonal rate design is consistent with the Department's rate design goals because it is fair, promotes rate continuity, is efficient, and is simple (Attorney General Brief at 137-138). The Attorney General recommends that after revenue requirement adjustments, the Department should adopt a $5.50 customer charge for Rates R-1 and R-2, and reduce the volumetric charges by an equal percentage to achieve the seasonal rate design for the residential class's share of the revenue requirement (Attorney General Brief at 138, citing Exh. AG-SJR-1, at 31; Attorney General Reply Brief at 76).

b. DOER

i. Demand Ratchets

DOER argues that the Company's demand ratchet proposal does not provide strong price signals to customers to reduce peak demand, and, therefore, violates the Department's goal of efficiency (DOER Brief at 5, citing D.P.U. 09-39, at 401; DOER Reply Brief at 3, citing D.P.U. 09-39, at 401). DOER contends that under the Company's proposal if a customer reaches a new monthly peak demand in a twelve month period, a demand ratchet increases the customer's demand charge immediately (DOER Brief at 4). DOER claims, however, that a customer would have to maintain a lower level demand for a year before that customer sees a lower demand charge because the charge is only reduced after a customer maintains lower peak monthly demand for eleven consecutive months (DOER Brief at 4-5). DOER argues that the eleven month lag in savings from a lower level demand reduces a customer's incentive to invest in technology that reduces peak demand, making those projects harder to justify because of the longer payback period for capital expenditure (DOER Brief at 5; DOER Reply Brief at 2-3). DOER maintains that it is common industry practice to justify capital investments for commercial customers with short payback periods (DOER Brief at 3). According to DOER, a project is considered more risky if the payback period is longer than one to three years (DOER Brief at 3).

Further, DOER argues that National Grid's analysis purporting to show that a hypothetical customer's energy efficiency savings is minimally impacted by the Company's proposed demand ratchet shows an incomplete picture (DOER Reply Brief at 1-2, citing Company Brief at 227-228; Exh. DPU-15-16). DOER contends that the Company's example uses a customer with a very flat load profile implementing energy efficiency measures (DOER Reply Brief at 1). DOER claims that the Company's example fails to consider the impacts on customers with a load that varies significantly month-to-month (i.e., customers that are more likely to implement peak demand reduction measures) (DOER Reply Brief at 2, citing Exh. DPU-15-16).

In this regard, DOER demonstrates the impact of the demand ratchet on a hypothetical customer with a high peak load implementing a project to reduce peak demand (kW), as opposed to an energy efficiency project reducing kWhs (DOER Reply Brief at 2). According to DOER, a Rate G-3 customer installing a solar plus storage project could reduce its summer peak demand from 400 kW to 250 kW and non-peak demand from 350 kW to 200 kW (DOER Reply Brief at 2). Further, DOER claims that this hypothetical customer expects an immediate reduction to its demand charge based on the new peak demand of 250 kW (DOER Reply Brief at 2). DOER asserts, however, that with a demand ratchet, the customer only sees a reduction to 300 kW (or 75 percent of the existing 400 kW summer peak demand) (DOER Reply Brief at 2). DOER notes that it is not until the investment has been in place for eleven months that the demand charges are assessed at the new demand and the full benefit of the demand reduction project is realized (DOER Reply Brief at 3). Thus, DOER asserts that because of the eleven month lag, a demand ratchet will increase the probability that a customer with a load that varies significantly month-to-month will not invest in demand reduction technologies (DOER Brief at 5; DOER Reply Brief at 2-3).

Finally, DOER argues that the high peak load to total load ratio customers are the exact type of Rate G-2 or Rate G-3 customers that should be incentivized to reduce their peak load, but are the most negatively impacted customers by the proposed demand ratchet (DOER Reply Brief at 3). Thus, DOER recommends that the Department direct the Company in its compliance filing to re-file Rate G-2 and Rate G-3 tariffs without demand ratchets, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 5; DOER Reply Brief at 3).

ii. Tiered Customer Charges

DOER does not object to the Company's proposed Phase I customer charge proposal, but opposes its Phase II rate design proposal for Rates R-1, R-2, and G-1 (DOER Brief at 6). DOER argues that the Department should reject the tiered customer charge proposal because it: (1) delays the benefits of, and thereby discourages customer investment in, energy savings measures; (2) disproportionately affects lower usage customers; and (3) does not serve as an appropriate proxy for a demand charge (DOER Brief at 7-8). Further, as described in more detail below, DOER contends that the Company did not demonstrate that its Phase II rate design proposal is consistent with the Department's rate structure goals and objectives (DOER Reply Brief at 4). DOER recommends that the Department reject the Company's Phase II proposal and direct the Company in its compliance filing to revise its tariffs to reflect a flat rate structure, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 6; DOER Reply Brief at 4).

Further, DOER argues that under the Company's Phase II rate design proposal, a customer will pay a higher customer charge based on the previous summer's usage even if the customer installs energy efficiency investments (e.g., efficient heating and cooling) to save money in the upcoming summer (DOER Brief at 7). According to DOER, a delay in savings discourages investment and affects the Commonwealth's goal to reduce energy costs (DOER Brief at 7). Moreover, DOER maintains that the Company did not analyze its Phase II rate design impacts on customer incentives to reduce consumption, including achievement of the Company's three-year energy efficiency plan (DOER Brief at 7, citing DOER 2-18(c); Tr. 5, at 634. Tr. 11, at 1-5, 16-20). Therefore, DOER asserts that the Company's tiered customer charge proposal should not be approved because it risks undermining the Commonwealth's energy policy goal of maximum deployment of energy efficiency (DOER Brief at 7).

(A) Fairness/Continuity

Regarding the rate design goals of fairness and continuity, DOER argues that low-use customers will incur higher bill impacts under the tiered customer charge proposal (e.g., a Rate R-2, low-use customer using 610 kWh per month will experience a 25 percent bill increase while a Rate R-2, high-use customer using 1,000-1,250 kWh per month will experience a 14 to 16 percent bill increase) (DOER Brief at 7-8, citing Exh. LI-JH-1, at 14). DOER expresses concern with these bill impacts because it claims that low-income customers tend to be low-use customers (DOER Brief at 8). Therefore, DOER recommends that the Department reject the Company's tiered customer charge proposal because it disproportionately (and negatively) affects lower and moderate income customers, thereby violating the Department's rate design goal of fairness (DOER Brief at 8).

(B) Efficiency

DOER rejects any notion that a customer's maximum monthly energy use in a year is a proxy for their demand (DOER Brief at 8, citing Tr. 5, at 635). According to DOER, a rate structure based on maximum demand should consist of a customer charge and a per-kW charge based on maximum kW demand (DOER Brief at 8; DOER Reply Brief at 4). Because the Company's tiered customer charges are not based on kW demand or the customer's maximum demand in a month, DOER maintains that the Phase II rate design proposal does not represent a true demand charge (DOER Reply Brief at 4). Further, DOER argues that the Company's tiered customer charge proposal uses a kWh charge as a proxy for demand, and therefore fails to consider a customer's coincident peak demand (DOER Brief at 8; DOER Reply Brief at 4). Accordingly, DOER maintains that the Company's tiered customer charges are not an appropriate and efficient proxy for demand charges (DOER Brief at 8; DOER Reply Brief at 3).

Moreover, because the Company's proposal is based on total kWh usage in a month, DOER argues that a customer does not receive the proper price signal, which a demand charge would provide, to adjust his or her energy consumption within a month (DOER Brief at 8; DOER Reply Brief at 4). For example, DOER contends that under the Company's tiered customer charge proposal, a customer charging an electric vehicle, doing laundry, and using an air conditioner at the same time would be billed the same amount as a customer staggering those activities throughout a month (DOER Brief at 8; DOER Reply Brief at 4). DOER maintains, however, that under a rate design with a true demand charge, the customer's bill would be lower under the staggered activity scenario (DOER Brief at 8; DOER Reply Brief at 4). Thus, for all of these reasons, DOER asserts that the Company's Phase II rate design is contrary to the Commonwealth's energy efficiency goals because it does not provide a price signal to reduce peak demand and lower system wide energy costs (DOER Reply Brief at 4).

c. Low Income Network

i. Phase I

The Low Income Network argue that the Department should reject the customer charge increases proposed by the Company in Phase I for low-income customers taking service on Rate R-2 (Low Income Network Brief at 13).[297] According to the Low Income Network, the Company's proposal to shift revenue collection from the volumetric rates to the customer charges burdens low-use customers that are disproportionately low-income (Low Income Network Brief at 13). The Low Income Network calculates the bill impacts for Rate R-2 customers that range from a 15.9-percent increase in Phase I to up to a 60-percent increase in Phase II (Low Income Network Brief at 14-15, citing Exhs. LI-JH-1, at 14; AG-SJR-1, at 28). Moreover, the Low Income Network argues that the Company's proposed increases to customer charges diverge from the Commonwealth's policies and programs designed to promote energy efficiency and investments in renewable energy and DG (Low Income Network Brief at 13-14).

297 While the Low Income Network's arguments are focused on low income customers and, therefore, on Rate R-2, many of the low-income customers take service on Rate R-1 (Low Income Network Brief at 13, n.39).

Therefore, the Low Income Network asserts that Rate R-2 customers will not be able to reduce the cost on their bills by reducing consumption under the Company's proposal (Low Income Network Brief at 14).

Further, the Low Income Network argues that a review of rate design proposals should take into account the differences between low income households and higher-income customers (Low Income Network Brief at 14). According to the Low Income Network, low income households generally have lower electric use than higher-income customers (Low Income Network Brief at 14). For example, the Low Income Network asserts that low-income customers on Rate R-2 have median monthly usage of approximately 460 kWh compared to the median usage for Rate R-1 customers of approximately 500 kWh per month (Low Income Network Brief at 14, citing Exhs. LI-JH-1, at 14; LI-2-10, Atts. 1 & 2).

ii. Tiered Customer Charges

The Low Income Network argues that the Department should also reject the Company's tiered customer charge proposal for Rate R-2 customers (Low Income Network Brief at 13). The Low Income Network maintains that the Company's proposed Phase II rate design will not achieve the rate design goals set forth by National Grid of ensuring that DG customers make a "modestly" greater contribution to Company distribution costs (Low Income Network Reply Brief at 3).

Further, the Low Income Network argues that the Phase II rate design proposal runs counter to the Commonwealth's energy efficiency and renewable energy goals (Low Income Network Brief at 15-16, citing Green Communities Act, Acts of 2008, c. 169; Global Warming Solutions Act, Acts of 2008, c. 298; An Act Relative to Solar Energy, Acts of 2016, c. 75; Low

Income Network Reply Brief at 3). The Low Income Network maintains that some of these energy efficiency policies date back to regulatory policies the Department established in the 1980s (Low Income Network Brief at 17, citing Order Opening Investigation, D.P.U. 11-120, at 1-2 (2011)). According to the Low Income Network, increasing customer charges and reducing volumetric charges reduces the incentive to implement energy efficiency measures because the value of each kWh saved is thereby reduced (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 14-15; Low Income Network Reply Brief at 4). Further, the Low Income Network claims that the customer charge tiers create a further barrier to energy efficiency because customers cannot lower their bills for up to twelve months (Low Income Network Brief at 16, citing Tr. 5, at 633-634; Low Income Network Reply Brief at 4). In addition, the Low Income Network maintains that the Company did not perform analysis of the impact of its Phase II rate design proposal on the adoption of energy efficiency measures or renewable energy technology (Low Income Network Brief at 16, citing Tr. 5 at 633-634).

According to the Low Income Network, the Company's tiered customer charge proposal creates barriers for low-income customers that conserve electricity to maintain low electricity costs (Low Income Network Brief at 15). The Low Income Network argues that the Company's tiered customer charge proposal increases the burdens on low income customers who tend to be low-use customers, which the Low Income Network maintains is contrary to the Department's fairness and continuity rate design goals (Low Income Network Reply Brief at 3, 4). Additionally, the Low Income Network contends that by definition, a low-use customer is less likely to contribute to peak demand than a high-use customer (Low Income Network Reply Brief at 4). The Low Income Network maintains that customer charges are assessed equally to all customers without considering monthly use, and therefore, customer charges affect customers with the lower use more than they affect customers with higher use (Low Income Network Reply Brief at 4). Under the Company's proposal, the Low Income Network claims that the median Rate R-2 customer would incur a bill increase of 25 percent and some customers would incur increases of more than 60 percent (Low Income Network Reply Brief at 4-5).

Further, the Low Income Network argues that the Company's tiered customer charge proposal may be confusing to customers (Low Income Network Brief at 16). According to the Low Income Network, customers will not understand their bills or how to control their use if volumetric charges are reduced, customer charges vary annually with use, and customers are unable to monitor their use in real time (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 15; Tr. 8, at 1308; Low Income Network Reply Brief at 4).

Additionally, the Low Income Network maintains that National Grid's proposed Phase II rate design is an inadequate proxy for demand, and, therefore, will not achieve the rate design goals set forth by the Company (Low Income Network Brief at 15, citing Exh. AG-SJR-1, at 16-17; Low Income Network Reply Brief at 3). According to the Low Income Network, the Company fails to prove that distribution costs are driven by maximum monthly energy use as a reflection of demand (Low Income Network Reply Brief at 3). As a result, the Low Income Network asserts that customers can be bumped into a higher tier that does not accurately correlate with the peak demands that drive system costs (Low Income Network Brief at 15). Moreover, the Low Income Network argues that the correlation between historical energy consumption and demand is weak and does not consider whether a customer's maximum historical demand occurred at a time coincident with local or system peaks (Low Income

Network Reply Brief at 3). Instead, the Low Income Network contends that the costs of meeting demand are driven by local and system peaks (Low Income Network Reply Brief at 3, citing DOER Brief at 8; Attorney General Brief at 130, 134; NECEC Brief at 2, 11).

iii. Conclusion

In sum, the Low Income Network argues that Massachusetts law supports minimizing the risk that low-income utility consumers will lose their utility service (Low Income Network Brief at 17, citing G.L. c. 164, § 1F(4)). Further, the Low Income Network contends that the Commonwealth has policies promoting energy efficiency and renewable energy (Low Income Network Brief at 17). In addition, the Low Income Network claims that National Grid's need for rate design reform does not outweigh customers' needs for rate continuity, low-income customers' need for affordability, and policy requirements for energy efficiency and equity, especially in light of the revenue stability provided through revenue decoupling and other risks compensated through the Company's rate of return (Low Income Network Reply Brief at 5). Accordingly, the Low Income Network recommends that the Department reject the Company proposals of raising customer charges and lowering volumetric energy charges because these proposals will undermine the Commonwealth's ability to achieve its energy goals (Low Income Network Brief at 17).

d. Limited Intervenors[298]

i. Demand Ratchet

EFCA argues that the Company did not properly support its demand ratchet proposal for Rates G-2 and G-3 (EFCA Brief at 17, 18-19; EFCA Reply Brief at 15-16).[299] According to

[298] For purposes of this section, the "Limited Intervenors" shall refer to Acadia Center, EFCA, NECEC, and Vote Solar, collectively.

EFCA, the Company did not analyze the basis of the demand ratchet's structure or its impact on current customers to support its proposal (EFCA Brief at 17, 18; EFCA Reply Brief at 16, citing Tr. 7, at 1,108). Moreover, EFCA contends that the only evidence that the Company provided to support its proposal was that a utility in Rhode Island implemented a demand ratchet in 1987 (EFCA Brief at 18; EFCA Reply Brief at 15). However, EFCA claims that the Company did not analyze the similarities and differences between Massachusetts and Rhode Island or the changing conditions over the last 30 years (EFCA Reply Brief at 15-16). EFCA asserts that demand ratchets are an obsolete rate design tool, and National Grid's "back-of-the-envelope" bill impact estimation is inadequate evidence to support the Company's proposed demand ratchet rate design (EFCA Reply Brief at 16, citing Exh. DPU-AC-1-3, Att. 1).

Moreover, EFCA argues that a demand ratchet conflicts with the Department's rate design goals and the concept of efficient price signals for use of resources (EFCA Brief at 6, 11-12; EFCA Reply Brief at 10, citing Exh. EFCA-TM/MW-1, at 8; Boston Gas Co. v. Department of Public Utilities, 405 Mass. 115, 116, (1989)). EFCA contends that, because a demand ratchet reduces the volumetric price signal, it reduces the incentive for customers to manage their use and, as such, may result in higher total energy consumption (EFCA Brief at 5-6, 11-12). Further, EFCA claims that a demand ratchet operates as a fixed charge because it

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[299] On September 9, 2016, EFCA filed with the Department a copy of the 2016 NARUC Draft Manual on Distributed Energy Resources Compensation, along with a cover letter and comments regarding the draft manual. In the cover letter, EFCA 'encouraged' the Department to consider certain aspects of the draft manual as we evaluate National Grid's proposed rate increase and design. On September 16, 2016, the Company filed a response to EFCA's filing. EFCA's filing was made well after the record closed, with no opportunity for inquiry. Further, the filing is related to a draft manual that apparently has not yet been adopted by NARUC. The filing constitutes extra-record evidence, to which the Department gives no probative weight. Further, we decline to take official notice of the draft manual pursuant to 220 C.M.R. § 1.10(2).

provides little incentive for a customer to reduce demand each month after the annual peak is set (EFCA Brief at 6, 13, 19). According to EFCA, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" (EFCA Brief at 13, citing Exh. EFCA-TW/MW-1, at 38; EFCA Brief at 19). Therefore, EFCA claims that a "fixed" demand charge does not account for the timing of a customer's demand, and its coincidence with the system peek, and also fails to reflect cost causation (EFCA Brief at 21).

Further, EFCA argues that demand ratchets discourage the adoption of new technologies (e.g., storage and DG), and EFCA notes that a customer with these technologies could face a 21 percent bill increase (EFCA Brief at 5-6; EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Moreover, EFCA contends that a customer with solar DG will incur a demand charge based on higher winter demand because there are more daylight hours in the summer than there are in the winter (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Thus, EFCA claims that the demand ratchet proposal does not recognize that these customers have low demand in the summer when the distribution system is most stressed (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). EFCA also asserts that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages without recognizing that these customers could reduce system costs for all customers (EFCA Brief at 20-21, citing Exh. EFCA-TW/MW-1 at 52).

EFCA also rejects the notion that there will be a "de minimis" impact of the demand ratchet on the first year of an investment, and EFCA argues that the Company's purported analysis showing the same is limited and does not prove that technology investment will not be "deleteriously" impacted (EFCA Reply Brief at 13-15, citing Company Brief at 227-228;

Exh. DPU-15-16). Instead, EFCA claims that its own analysis show a range of bill impacts, such as bill increases of: 2.6 percent (i.e., similar to the Company's analysis), five percent, and 21 percent (EFCA Reply Brief at 15, citing Exh. EFCA-TW/MW-1, at 50).

According to EFCA, the Company has not carried its burden of proof to warrant approval of the demand ratchet (EFCA Reply Brief at 12). Accordingly, EFCA recommends that the Department reject the Company's demand ratchet proposal (EFCA Brief at 6, 13, 21).

ii. Tiered Customer Charges

(A) Introduction

The Limited Intervenors argue that the Department should reject the Company's tiered customer charge proposal (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 1; Vote Solar Brief at 7). According to the Limited Intervenors, the Company's proposed Phase II rate design does not meet one or more of the Department's rate design goals (i.e., fairness, continuity, simplicity or understandability, efficiency or cost causation) (Acadia Center Brief at 2, 12; EFCA Brief at 3, 15; NECEC Brief at 1, 9; NECEC Reply Brief at 1; Vote Solar Brief at 7).

Further, the Limited Intervenors argue that the Company did not provide evidence of a cost shift from DG customers to non-DG customers or further analysis to support its Phase II rate design proposal (Acadia Center Brief at 2, 10; Acadia Center Reply Brief at 3; EFCA Brief at 9, citing Exh. NG-PP-1, at 28; EFCA Reply Brief at 4; Vote Solar Brief at 7, 8, citing Exhs. NG-PP-1, at 28; NG-PP-Rebuttal-1, at 53; Tr. 5, at 616-617; NECEC Brief at 45-46; NECEC Reply Brief at 1-2, 8-9). Specifically, the Limited Intervenors argue that the Company did not properly analyze the costs or benefits attributable to DG customers in its service territory

(Acadia Center Brief at 12; Acadia Center Reply Brief at 3; EFCA Brief at 9-10, citing Exhs. EFCA-TW/MW-1, at 19, 34, 36; EFCA-TW/MW-Rebuttal-1, at 5 n.9; EFCA-1-11; Tr. 7, at 1,067, 1,070-1,071; EFCA Reply Brief at 4-8; NECEC Brief at 46, citing Exh. LI-1-10; Tr. 5, at 602; Vote Solar Brief at 8, citing Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; Tr. 5, at 620; Vote Solar Reply Brief at 4). According to the Limited Intervenors, without quantifying the costs and benefits attributable to DG customers, the Company cannot demonstrate that a cost-shift occurs (Acadia Center Brief at 10-12; EFCA Brief at 10; NECEC Brief at 45-46, citing Exh. EFCA-TM/MW-1, at 21-22; Vote Solar Reply Brief at 3-4). Thus, the Limited Intervenors claim that because the Company has not proven a cost shift with any analysis, its proposed Phase II rate design is not even necessary (Acadia Center Brief at 12; EFCA Brief at 10-11; EFCA Reply Brief at 4; NECEC Reply Brief at 8-10; Vote Solar Brief at 9; Vote Solar Reply Brief at 3-5). Further, EFCA and NECEC argue that National Grid did not analyze the effects of the tiered customer charges on the Company's alleged cost shift (EFCA Brief at 12, citing Exh. EFCA-1-2; NECEC Reply Brief at 8-9).

NECEC and Vote Solar also argue that the Company has not met its burden with analysis to show that its "ideal rate design," which includes actual residential demand charges, is just and reasonable, in the public interest, and desirable (NECEC Brief at 10-11; NECEC Reply Brief at 2; Vote Solar Reply Brief at 2-3, citing Fitchburg Gas Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 582 (1978)). For example, Vote Solar contends that the Company did not provide evidence showing that actual demand charges will change residential and small C&I behavior or that these customers understand demand charges and have the tools to manage peak demand (Vote Solar Reply Brief at 3, citing Exh. VS-NP-1, at 39-40). Further, NECEC claims that the Company's Phase II rate design does not meet its intent of moving toward demand charges, and Vote Solar argues that no other state-regulated utility in the country requires mandatory demand charges for residential customers (NECEC Brief at 9; Vote Solar Brief at 1). Finally, NECEC and Vote Solar assert that no other utility has implemented a rate design similar to the Company's proposal (NECEC Brief at 45, citing Exh. NECEC-RTB-1, at 14, 35; Tr. 5, at 654-657; Vote Solar Reply Brief at 1, citing Exh. DPU-12-2, Tr. 5, at 638-641).

(B) G.L. c. 164 § 141[300]

EFCA, NECEC, and Vote Solar claim that the Company's proposed Phase II rate design runs counter to state policy to promote energy efficiency and DG and may result in higher electricity prices for all electric customers in the Commonwealth (EFCA Brief at 2, 4; NECEC Reply Brief at 12-13; Vote Solar Brief at 1, 22). In particular, Vote Solar notes that the relevant portion of G.L. c. 164 § 141 ("§ 141) provides: "[i]n 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" (Vote Solar Brief at 22, citing § 141).

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300 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.

In Section XIII.E below, we address § 141 as it relates to the impact of on-site generation on affordability of electric service for low income customers, as provided by the second clause of § 141.

According to Vote Solar, the Company did not provide evidence regarding the impact of its tiered customer charges on energy efficiency, compliance with the three-year energy efficiency plan, and incentives to lower demand (Vote Solar Brief at 22-23, citing Exh. DOER-2-18; Tr. 5, at 634; Vote Solar Reply Brief at 11-12). Vote Solar argues that customers are incentivized to implement energy efficiency by the opportunity to save money through lowering their total kWh charges (Vote Solar Brief at 22, citing Exh. DOER-2-16; Tr. 5, at 632; Acadia Center Reply Brief at 7). However, Vote Solar maintains that the purpose of National Grid's tiered customer charges are "to ensure that customers who reduce kWh consumption either through implementation of DG or energy efficiency will pay their fair share of the Company's distribution system," shifting cost recovery away from the kWh charges and causing kWh rates to decline (Vote Solar Brief at 22, citing Exh. NG-PP-1, at 32, 64; Tr. 5, at 750). Vote Solar maintains that the Company does not dispute this evidence (Vote Solar Reply Brief at 11).

Acadia Center challenges the Company's analysis that purportedly shows that tiered customer charges have no effect on energy efficiency, and argues that such analysis is "cherry-picked" and misleading (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). In particular, Acadia Center contends that the Company's analysis shows a Tier 3 customer using 650 kWh per month reducing consumption by 23 percent after installing energy efficiency technology, causing the customer to drop to Tier 2 with a new baseline of 500 kWh (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). However, Acadia Center claims that under the same scenario, with a Tier 3 customer using 800 kWh per month, the customer would not drop to Tier 2 after the 23-percent reduction in consumption (Acacia Center Reply Brief at 7, n.27, citing Exh. LI-1-14, Att.).

Further, Vote Solar argues that it is not advocating for "an absolute ban on any rate design that would affect existing incentives for customers to pursue DG and energy efficiency" (Vote Solar Reply Brief at 12, citing Company Brief at 222). Instead, Vote Solar maintains that the Company did not provide the evidence to satisfy its statutory obligation in the instant proceeding (Vote Solar Brief at 22-23, citing § 141; Vote Solar Reply Brief at 12-13).

Moreover, NECEC and Vote Solar argue that § 141 does not require the Department to consider the impacts of the Company's proposed rate design along with the incentives that are provided to energy efficiency and on-site generation (Vote Solar Reply Brief at 12-13, citing Company Brief at 222 (emphasis in original); NECEC Reply Brief at 12-13, citing Company Brief at 222). Rather, NECEC asserts that the Department must be mindful of the effects of rate design on the development of energy efficiency and on-site generation (NECEC Reply Brief at 13).

(C) Continuity and Fairness

Some of the Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's continuity goal and does not improve customer equity (Acadia Center Brief at 2, 12-13; Acadia Center Reply Brief at 5; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 27; NECEC Reply Brief at 11). In particular, NECEC contends that the Phase II rate design proposal is based on arbitrary factors that drive significant changes in customers' distribution bills (NECEC Brief at 9). Further, EFCA and NECEC calculate that under the Company's proposal the residential customer charge will increase by up to 400 percent and the small commercial customer charge will increase by up to 200 percent (EFCA Brief at 16; NECEC Brief *at* 27, citing Exh. EFCA-TM/MW-1, at 7, 40). In addition, according to Acadia Center and NECEC, residential annual distribution bill impacts will range from approximate decreases of 10 percent to increases of over 100 percent (Acadia Center Brief at 13, citing Exh. AG-SJR-1, at 26-28; NECEC Brief at 28, citing Exhs. AG-SJR-1, at 24, 27-28; AG-SJR-10). More specifically, NECEC notes that ten percent of R-1 customers will incur bill increases of 45 percent or more, and 1,000 R-2 customers will incur bill increases of 60 percent or more (NECEC Brief at 28, citing Exhs. AG-SJR-1, at 27-28; AG-SJR-10; NECEC Reply Brief at 11-12). Further, NECEC claims that customers will be subjected to two significant changes in rate structure within a short period of time; first, the Company's Phase II proposal, then time-varying rates pursuant to the Department's decision in Time Varying Rates, D.P.U. 14-04-C (2014) (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42). NECEC asserts that these two consecutive rate changes violate the Department's rate design goal of continuity (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42).

Acadia Center argues that the proposed Phase II rate design is not fair because it shifts cost burden from high-use customers to low-use customers, and low-use customers are disproportionately low-income customers (Acadia Center Brief at 12-13, citing Exh. DPU-AC-1-2, Att.; Acadia Center Reply Brief at 5). For example, Acadia Center calculated only a $5 bill increase for a customer using 2,000 kWh per month, but a $10 monthly bill increase for a customer using 600 kWh per month (Acadia Center Brief at 13, citing Exhs. AC-1-8, Att.; NG-AC-1-1, Att. 1 at 1). Further, Acadia Center contends that approximately 25 percent of customers with usage above the highest tiered customer charge cutoff would pay a per-kWh rate that is lower than their current tail block per-kWh rate (Acadia Center Brief at 13; Acadia Center Reply Brief at 5-6).

Further, Vote Solar maintains that the Company's Phase II rate design proposal is a punitive, one-sided ratchet, proposed without any supporting analysis to determine how likely customers are to move to different tiers (Vote Solar Brief at 18-19, citing Tr. 5, at 631). According to Vote Solar, using twelve months of historical use information to identify maximum monthly use is unreliable because the Company did not study whether the maximum monthly use for a customer is consistent year to year (Vote Solar Brief at 17, citing Exh. NG-PP-Rebuttal-1, at 29; Tr. 5, at 728-729; RR-NECEC-1, Att.; Vote Solar Reply Brief at 8-9). Moreover, NECEC contends that similar customers could have nearly identical patterns of use (e.g., customer one uses 600 kWh in a billing period while customer two uses 599 kWh), but a customer on Tier 3 for distribution services is billed 33 percent more than a customer on Tier 2 (NECEC Brief at 22, citing Exh. EFCA-TW/MW-1, at 33; NECEC Reply Brief at 12). Therefore, NECEC argues that this divergence of bills is unfair and does not reflect cost of service differences (NECEC Brief at 22-23).

(D) Simplicity

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's simplicity goal (Acadia Center Brief at 2, 14; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 23, citing D.T.E./D.P.U. 06-82-A, at 75; NECEC Reply Brief at 10; Vote Solar Brief at 15-16; Vote Solar Reply Brief at 8-9). Further, Acadia Center contends that the Company's Phase II rate design proposal is a departure from traditional rate design and should have included bill management tools because potential bill impacts are large (Acadia Center Reply Brief at 6).

The Limited Intervenors also argue that customers cannot easily monitor, respond to, and manage bills under the Company's proposed Phase II rate design, and NECEC alleges that customers would find the adjustment to a tiered customer charge difficult (Acadia Center Brief at 14; Acadia Center Reply Brief at 6; EFCA Brief at 15, citing Exh. LI-2-12; NECEC Brief at 23-25, 27, citing Exhs. EFCA-TW/MW-1, at 41; NECEC-RTB-Rebuttal-1, at 16; Vote Solar Reply Brief at 8). Further, NECEC and Vote Solar contend that customers will not know when they are close to a tier boundary because they are unable to monitor use in real time (NECEC Brief at 25, citing Exh. LI-2-12; Tr. 5, at 626-627; Vote Solar Brief at 16; Vote Solar Reply Brief at 8). Additionally, Acadia Center and NECEC claim that customers will not understand what kinds of behavior will move them to a higher tier or whether energy efficiency and conservation measures will drop them into a lower tier (Acadia Center Brief at 14; NECEC Brief at 24-25). Accordingly, NECEC asserts that an arbitrary event could set a customer's new maximum annual kWh and move the customer into a higher tier (NECEC Brief at 25).

NECEC also argues that the Company's proposed Phase II rate design is complex and leaves other arbitrary consequences in place, such as the length of a billing period, number of weekend days within a billing period, and estimated meter reads, that could affect a customer's maximum monthly use and customer charge tier for an entire year (NECEC Brief at 22, citing Exhs. AG-SJR-1, at 24-26; NG-PP-Rebuttal-1, at 63; AG-SJR-Rebuttal-1, at 16; NECEC Reply Brief at 12). Further, Vote Solar contends that a customer may take action to lower his or her maximum monthly use, but it may not result in a bill reduction (Vote Solar Brief at 17-18, citing Tr. 5, at 629; Vote Solar Reply Brief at 9). NECEC and Vote Solar maintain that it is unfair to subject customers to a higher tiered customer charge for twelve months based on one month's use, but to be moved to a lower tier, the customer must wait until he or she sustains a reduction in maximum use for twelve months (NECEC Brief at 22; Vote Solar Brief at 18-19, citing Tr. 5, at 630-631; Vote Solar Reply Brief at 8). EFCA describes the tiered customer charge proposal as having the same effect as the demand ratchet proposal for Rates G-2 and G-3 (EFCA Reply Brief at 9-10, citing Exh. EFCA-TW/MW-1, at 11).

Vote Solar also rejects the notion that customers are able to respond to demand charges, and, therefore, the Company's tiered customer charge proposal is acceptable, as Vote Solar argues that the Company's position is based on its experiences with larger commercial customers, not residential customers (Vote Solar Brief at 15-16, citing Tr. 5, at 675-676). Further, NECEC contends that residential and small commercial customers will not understand demand, much less the relationship between demand and their monthly use (NECEC Brief at 24, citing Exhs. VS-NP-Rebuttal-1, at 18; EFCA-TM/MW-1, at 41).

Moreover, NECEC and Vote Solar argue that there is no evidence in National Grid's Smart Energy Solutions Program, which studied customer behavior under time-of-use/critical peak pricing and peak-time rebate programs, that supports the Company's position that customers would understand the tiered customer charge proposal (Vote Solar Brief at 16, citing Tr. 5, at 624-626; NECEC Brief at 23-24, citing Exh. NECEC-RTB-Rebuttal-1, at 15; Tr. 5, at 625; NECEC Reply Brief at 10, citing Tr. 5, at 625-626). Further, although the Company plans to implement an outreach and education program for its tiered customer charges, NECEC and Vote Solar contend that the Company did not develop the materials and present this evidence (NECEC Reply Brief at 11; Vote Solar Brief at 17, citing Exh. VS-2-6; Vote Solar Reply Brief at 9).

Finally, in response to the Company's argument that time-varying rates are complicated, Acadia Center and NECEC maintain that customers are able to respond to time-varying prices for other products, such as travel and cell phones (Acadia Center Reply Brief at 6; NECEC Reply Brief at 10). Acadia Center asserts that as technology advances, more complicated rate designs become more feasible (Acadia Center Reply Brief at 5-6).

(E) Efficiency

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's rate design goal of efficiency because it does not send transparent price signals, it is not based on cost-causation principles, it is not an improvement from current rate design, and it is unjustified (Acadia Center Brief at 2, 14, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 3; EFCA Reply Brief at 11; NECEC Brief at 14, 16-17, 23; Vote Solar Brief at 9-10, 12 n.8, 15). Therefore, the Limited Intervenors claim that the Company's tiered customer charge proposal fails to represent an efficient, cost-based rate design (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 7-9; EFCA Reply Brief at 11; NECEC Reply Brief at 2-3; Vote Solar Brief at 15).

Further, EFCA contends that the Company has conflated historical and future costs in designing its tiered customer charges (EFCA Brief at 14). In this regard, EFCA notes that historical costs are fixed, sunk costs, but the purpose of rate design is to not only recover historical costs, but also to send clear price signals in order to encourage the efficient use of the distribution system and reduce avoidable future costs (EFCA Brief at 14). EFCA contends that the volumetric rate sends a price signal to customers that reduced system use results in reduced costs (EFCA Brief at 14). Further, EFCA maintains that this price signal will reduce the need for supply-side resources, and, therefore, reduce long-run electricity costs for all customers (EFCA Brief at 15). Thus, EFCA and Vote Solar assert that the tiered customer charge proposal does not "provide strong signals to customers to decrease excess energy consumption in consideration of price and non-price social, resource, and environmental factors" because customers will be locked into a tier for a year (EFCA Brief at 4, 15; Vote Solar Reply Brief at 8-9). Accordingly, EFCA and Vote Solar maintain that such results are contrary to the Department's goal of achieving efficient price signals and efficiency in customer consumption decisions (EFCA Brief at 15; Vote Solar Reply Brief at 8-9).

Moreover, the Limited Intervenors disagree with the Company's portrayal of the relationship between a customer's maximum monthly kWh use and maximum hourly kW demand (Acadia Center Brief at 14-15; EFCA Brief at 15; NECEC Brief at 17; NECEC Reply Brief at 3-4; Vote Solar Brief at 9-10). According to NECEC and Vote Solar, the low R-squared[301] values produced from the Company's analysis demonstrate a weak relationship between maximum billed use and maximum hourly load for each customer charge tier, and therefore, maximum annual kWh serves as poor proxy for a customer's contribution to non-coincident peak demand (NECEC Brief at 16-18, citing Exh. VS-NP-1, at 26; Vote Solar Brief at 10-12, citing Exh. AG-SJR-5; DPU-9-8; Tr. 5 at 637-638, 688-689; Vote Solar Reply Brief at 6, citing Exh. DPU-9-8, Att.). Further, EFCA, NECEC, and Vote Solar argue that a

301 The R-squared analysis measures the strength of a relationship (Exh. DPU-15-9; Tr. 8, at 1218). A R-squared value of one means that the model explains all the variability of the data, and a R-squared value of zero means that the model explains none of the variability of the data (Tr. 5, at 636).

customer's highest month of use is a worse indicator of the customer's maximum demand than a customer's average energy use (i.e., current rates) (EFCA Brief at 15; EFCA Reply Brief at 11, citing Exh. EFCA-TW/MW-1, at 25-28; NECEC Brief at 17-18, citing Exhs. NECEC-RTB-1, at 19-20; DPU-NECEC-1-4, Att.; EFCA-TW/MW-1, at 27-29; RR-DPU-27, Att.; NECEC Reply Brief at 5; Vote Solar Brief at 12, n.8, citing Exh. NECEC-RTB-1, at 19-20; RR-DPU-27, Att.; DPU-9-8, Att.).[302]

According to the Limited Intervenors, a tiered customer charge based on a customer's maximum monthly kWh use as a proxy for non-coincident peak demand is an inferior metric because it does not link rate design to the distribution system peak loads that drive distribution system costs (Acadia Center Brief at 15, citing Exh. AC-AA-Rebuttal-1, at 1-2; Acadia Center Reply Brief at 8-9; EFCA Brief at 16; NECEC Brief at 11; NECEC Reply Brief at 4; Vote Solar at 9-10, 12, 13, citing Fitchburg Gas and Electric Light Company 375 Mass. at 582). Vote Solar and NECEC contend that system costs are incurred based on customer's demand coinciding with collective peak demand of all customers, which Vote Solar claims that the Company acknowledges (NECEC Reply Brief at 4; Vote Solar Brief at 13-14, citing Exhs. NG-PP-1, at 31; VS-NP-1, at 27; EFCA-TW/MW-1 at 26-27; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, EFCA and Vote Solar claim that the Company did not perform an analysis showing that non-coincident peak demand charges actually reflect a customer's contribution to system costs, improve system utilization, cause customers to shift use in a way that reduces use during peak system hours, or reduce system costs (EFCA Brief at 16; NECEC Brief at 16; NECEC

302 EFCA contends that the Company acknowledges its analysis was inadequate, and Vote Solar maintains that the Company admitted its tiered customer charge proposal was a "second-best solution" (EFCA Reply Brief at 11, citing Tr. 5, at 688; Vote Solar Brief at 2, 10, n.6, citing Exh. NG-PP-1, at 31; Tr. 5, at 637).

Reply Brief at 3-4; Vote Solar at 14, citing Tr. 5, at 677-679). NECEC maintains that distribution system costs are highly dependent on the time of day and the time of year that services are used, and distribution system costs result from the infrastructure needed to provide service during times of the highest customer use (NECEC Brief at 11-12, citing Exhs. NECEC-RTB-1, at 18; VS-NP-Rebuttal-1, at 7; Tr. 5, at 666-667, 774; Vote Solar Brief at 13, citing Exhs. NG-PP-1, at 31; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, Vote Solar asserts that the Company admitted that reductions in customer use during peak hours benefit the system and reduces costs (Vote Solar Brief at 13, citing Tr. 5, at 681). NECEC maintains that rate design should be based on costs incurred during times when demand is the highest (NECEC Brief at 12, citing Exhs. NECEC-RTB-1, at 18; AC-AA-Rebuttal-1, at 1; EFCA-TW/MW-1, at 26-27; VS-NP-1, at 27; VS-NP-Rebuttal-1 at 7; Tr. 5, at 774). Given these considerations, the Limited Intervenors claim the tiered customer charges, based on an individual customer's non-coincident peak demand, is not an improvement over standard volumetric charges and does not improve cost-causation (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 8, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 15, citing Exh. EFCA-TW/MW-1, at 25; NECEC Brief at 16-19; NECEC Reply Brief at 5; Vote Solar Brief at 12-15; Vote Solar Reply Brief at 6).

NECEC argues that the Company's proposed Phase I rates and current rates are more reflective of the cost to serve than the Company's proposed Phase II rates (NECEC Brief at 15-16, citing Exhs. AG-SJR-20-30; AG-SJR-6; AG-SJR-7; AG-SJR-8). For example, NECEC claims that under Phase I rates, a $1 increase in cost of service would correspond to a 57 cent increase in revenue recovery, but under Phase II rates, the same $1 increase would correspond to only a 54 cent increase in revenue recovery (NECEC Brief at 16, citing Exhs. AG-SJR-1, at 22-23; AG-SJR-7; AG-SJR-8).

EFCA takes issue with Company's argument that a customer's maximum demand represents a customer's potential to contribute to the capacity requirements of the distribution system (EFCA Reply Brief at 10-11, citing Company Brief at 220-221; Exh. EFCA-TW/MW-1, at 25). According to EFCA, a customer's individual peak demand will not put the greatest strain on the system because individual peaks do not occur at the exact same time for all customers (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13).

Further, the Limited Intervenors argue that the Company's counter argument that existing distribution demand charges already are based on non-coincident peak demand is flawed (Acadia Center Reply Brief at 8-9; EFCA Reply Brief at 10-11; NECEC Reply Brief at 4; Vote Solar Reply Brief at 7). In particular, Acadia Center contends that the Company does not explain why non-coincident peak demand is the basis of existing demand charges, and argues that metering limitations are a primary reason that existing demand charges are based on the non-coincident peak demand during a billing period (Acadia Center Reply Brief at 9). According to Vote Solar and NECEC, existing demand charges for large C&I customers do not justify application of such charges to small C&I and residential customers because these customers do not use the distribution system in the same way (Vote Solar Reply Brief at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12-13, citing Exhs. NECEC-RTB-1, at 27; VS-NP-1, at 27; NECEC Reply Brief at 4-5). Further, Vote Solar maintains that many small customers share one feeder, creating diversity of demand, whereas a medium or large C&I customer can comprise the majority of demand on an individual feeder (Vote Solar Reply Brief at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12, n.5, citing NECEC-RTB-1, at 27, 29; VS-NP-1, at 27; VS-CP-Rebuttal-1, at 12-13; NECEC Reply Brief at 5). Moreover, NECEC contends that peak demand drives that the size and costs of the distribution system (NECEC Brief at 12, citing Exh. NG-PP-1, at 30, 33; NG-PP-Rebuttal-1, at 13; AG-SJR-Rebuttal-1, at 15; NG-PP-2; Tr. 10, at 1557-1558, 1574-1575). Thus, EFCA, Vote Solar, and NECEC argue that the Company's proposed Phase II rate design approach ignores diversity of demand, discussed in planning for distribution system investment (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13; NECEC Brief at 11; NECEC Reply Brief at 4-5; Vote Solar Reply Brief at 7).

Finally, according to NECEC, tiered customer charges are an inaccurate measure of cost causation for customers who have installed solar DG (NECEC Brief at 20). NECEC maintains that solar DG customers typically reduce demand during summer months and are likely to have higher demand during off-peak months on the distribution system (NECEC Brief at 20, citing Exh. NECEC-RTB-1, at 21-24). Accordingly, NECEC asserts that tiered customer charges fail to provide accurate price signals indicating the value that solar DG provides in reduced costs on the distribution system (NECEC Brief at 21).

(F) Conclusion

In sum, the Limited Intervenors argue that the record does not support a finding that the Company's tiered customer charge proposal is just and reasonable (Acadia Center Brief at 2; EFCA Brief at 11; NECEC Reply Brief at 9-10; Vote Solar Brief at 7, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 264, n.13 (2002)). Further, Vote Solar claims that no other utility uses a rate design similar to the Company's proposed tiered customer charges (Vote Solar at 3, citing Exh. DPU-2-12; Tr. 5, at 640). Therefore, the Limited Intervenors conclude that National Grid has not met its burden to justify the tiered customer charge proposal, and the Department should reject it (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 3; Vote Solar at 9, citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 582 (1978)).

iii. Seasonal Rate Design

Acadia Center and NECEC support the Attorney General's seasonal rate design proposal (Acadia Center Brief at 2, 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30). According to NECEC, the Department stated that it would consider seasonally differentiated rates where they were shown to more effectively indicate the underlying costs of the distribution system and encourage efficient consumption of electricity (NECEC Brief at 29, citing D.P.U. 10-70, at 330). Acadia Center and NECEC allege that the Attorney General's rate design proposal improves the relationship to cost of service compared to the Company's Phase I and Phase II rate design proposal (Acadia Center Brief at 17, 18; NECEC Brief at 29, citing Exhs. AG-SJR-1, at 22-24, 30; AG-SJR-7; AG-SJR-8; AG-SJR-12).

Acadia Center and NECEC also argue that the Attorney General's seasonal rate design meets the Department's rate making goals (Acadia Center Brief at 18; NECEC Brief at 29-30). They assert that the seasonal rate design is cost-based, results in reasonable bill impacts, is simple and understandable, and improves efficiency and cost causation (Acadia Center Brief at 18; NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 27-28, 30; NECEC-RTB-Rebuttal-1, at 3, 12; EFCA-TW/MW-Rebuttal-1, at 22-23).

Further, NECEC argues that a higher rate in the summer months would better align time of use with underlying costs (NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 16-20; AG-SJR-2; AG-SJR-4; AG-SJR-5). In this regard, NECEC contends that bill impacts range from 10 percent to 38 percent (compared to negative 14 percent to 181 percent under the Phase II rate design proposal) (NECEC Brief at 29, citing Exh. SG-SJR-1, at 27-28, 30). According to NECEC, the Rate G-1 seasonal rate design has similar bill impacts to the Company's proposed Phase I rate design (NECEC Brief at 30, n.15, citing RR-DPU-47; Tr. 10, at 1569-1570). Finally, NECEC asserts that seasonal rates are more efficient, do not require advanced meters, and can be implemented in conjunction with time-varying rates (NECEC Brief at 30, citing D.P.U. 14-04-C; Exhs. EFCA-TW/MW-Rebuttal-1, at 22-23; NECEC-RTB-Rebuttal-1, at 12-13).

NECEC also argues that the Company disputed the Attorney General's proposed seasonal rate design with two, unconvincing arguments (NECEC Reply Brief at 13). First, NECEC rejects the Company's argument that system-wide coincident peak demand reduction from a seasonal rate design is not beneficial because some feeders might not realize a reduction in their peak demand, as NECEC notes that the majority of the Company's feeders peak in the summer (NECEC Reply Brief at 14, citing Exhs. NECEC-RTB-Rebuttal-1 at 9-10; NG-PP-Rebuttal-1, at 14-15; NECEC-1-7; Company Brief at 224). Thus, NECEC asserts it cannot be disputed that for nearly all feeders, summer electricity use is the driver of demand-related system costs (NECEC Reply Brief at 14, citing Company Brief at 199, 217).

Second, NECEC rejects the Company's argument that seasonal rates will result in "arbitrarily" higher net metering credits (NECEC Reply Brief at 14, citing Company Brief at 224). According to NECEC, the higher value of net metering credits in the summer months from the Attorney General's proposed seasonal rate design are not "arbitrary" because the value of net metering credits will rise with summer distribution rate (NECEC Reply Brief at 14). Further, NECEC contends that a higher summer rate is appropriate because cost responsibility for the majority of demand-related costs is based on the customer class contribution to summer peak demands in the Company's allocated COSS (NECEC Reply Brief at 14, citing Exhs. AG-SJR-1, at 17, 29-30; AG-SJR-Rebuttal-1, at 15-16). Therefore, NECEC asserts that there is nothing arbitrary about crediting excess generation from net metering facilities at a higher rate when that rate accurately reflects the increased value of the demand reduction associated with that generation during the summer months (NECEC Reply Brief at 14).

e. AIM and TEC

AIM and TEC argue that National Grid did not properly support its demand ratchet proposal for Rates G-2 and G-3 and did not analyze the impacts of the demand ratchet proposal on current customers (AIM and TEC Reply Brief at 8). According to AIM and TEC, the Company's own evidence contradicts its basis for proposing the demand ratchet (AIM and TEC Reply Brief at 8). For example, AIM and TEC contend that Rate G-3 customers' demand patterns show that the Rate G-3 class load is different than demand during the monthly system coincident peak (AIM and TEC Reply Brief at 5, citing Exh. NG-PP-3(b)). AIM and TEC claim that this data contradicts the Company's assertion that a customer's maximum demand during an annual period reflects the customer's contribution to coincident peak demand (AIM and TEC Reply Brief at 5). According to AIM and TEC, National Grid sizes its circuits to accommodate coincident peak demand, not the summation of non-coincident peak demands (AIM and TEC

Reply Brief at 5). Thus, AIM and TEC contend that cost causation occurs when a customer's peak demand coincides with the maximum monthly peak demand (AIM and TEC Reply Brief at 5). Therefore, AIM and TEC claim that because a demand ratchet does not account for the timing of a customer's demand, and its coincidence with system peak, and because it fails to reflect cost causation, the demand ratchet results in a fixed annual charge (AIM and TEC Reply Brief at 7). Accordingly, AIM and TEC assert that the Department should reject the Company's claim that all Rate G-2 and Rate G-3 customers pay for demand through a demand ratchet that is based on their annual peak load, regardless of when it occurs (AIM and TEC Reply Brief at 5).

Further, AIM and TEC argue that the demand ratchet proposal will reduce customer incentives for behavior that is beneficial to the system and demand reduction goals (AIM and TEC Reply Brief at 7). AIM and TEC agree with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth because it operates as a fixed charge (AIM and TEC Reply Brief at 7-8).

Moreover, AIM and TEC argue that the demand ratchet is really a "de facto" stand-by charge for customer's with behind the meter DG because these customers will not be able to reduce their demand charge for an entire year (AIM and TEC Reply Brief at 4, 6, 8). In this regard, AIM and TEC contend that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages (e.g., combined heat and power ("CHP")) without recognizing the benefit of demand reductions that could reduce system costs for all customers (AIM and TEC Reply Brief at 6). For example, AIM and TEC claim that a customer with a 30-minute CHP outage during a month that the grid has excess capacity (e.g., April) could result in additional demand charges of over $21,000 for that twelve-month period (AIM and TEC

Reply Brief at 6). Further, AIM and TEC maintain that some customers with DG must interrupt on-site generation when there are power quality issues completely beyond the customer's control (AIM and TEC Reply Brief at 6). Moreover, AIM and TEC note that current DG owners schedule maintenance during off-peak periods to avoid demand charges (AIM and TEC Brief at 7). According to AIM and TEC, a demand ratchet eliminates the incentive to schedule maintenance during off-peak periods because demand charge cost avoidance can no longer justify the added cost of overtime and weekend labor rates for the off-peak work (AIM and TEC Reply Brief at 7). Thus, AIM and TEC assert that the Company's demand ratchet proposal will unfairly penalize these customers and cause negative impacts for customers with distributed resources (AIM and TEC Reply Brief at 6-7).

AIM and TEC also take issue with National Grid's hypothetical customer example, and they argue that it represents a business only operating in the summer and thereby only paying a demand charge during the summer, but requiring a fixed distribution investment from the Company to accommodate this customer's peak load (AIM and TEC Reply Brief at 4-5, citing Exh. NG-PP-1, at 59). AIM and TEC contend that the scenario the Company modeled to support its proposal for a demand ratchet is rare and should not be used to justify a new charge applying to all customers (AIM and TEC Reply Brief at 5).

In light of these considerations, AIM and TEC argue that the Company has not carried its burden of proof to warrant approval of the proposed demand ratchet (AIM and TEC Reply Brief at 8, citing D.T.E. 99-118, at 7, n.5). Additionally, AIM and TEC argue that the Company's rationale for its demand ratchet proposal is confused, illogical, and flawed, and the Company's proposal violates the Department's rate design principles (AIM and TEC Reply Brief at 4, 7-8).

Thus, AIM and TEC recommend that the Department reject the Company's demand ratchet proposal (AIM and TEC Reply Brief at 10).

f. PowerOptions

i. Demand Ratchet

PowerOptions argues that the Company did not properly support its demand ratchet proposal for Rate G-2 and Rate G-3 because it did not provide evidence of the impacts of the demand ratchet proposal on current customers (PowerOptions Reply Brief at 5-7). Further, PowerOptions claims that the Company's demand ratchet proposal is a sweeping change in the manner of billing medium and large C&I customers (PowerOptions Reply Brief at 6).

PowerOptions argues that the Company's demand ratchet operates as a fixed charge (PowerOptions Reply Brief at 7). According to PowerOptions, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" because it provides little incentive to reduce demand each month after the peak has been set (PowerOptions Reply Brief at 7).[303] Therefore, PowerOptions contends that a fixed demand charge does not account for the timing of customer demand and its coincidence with the system peak, and also fails to reflect cost causation (PowerOptions Reply Brief at 7). Thus, PowerOptions claims that the demand ratchet proposal is unfair and causes negative impacts for customers with distributed resources (e.g., solar) (PowerOptions Reply Brief at 7).

Further, according to PowerOptions, the Company's billing demand definitions are confusing for customers (PowerOptions Reply Brief at 6). PowerOptions maintains that

[303] PowerOptions agrees with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth (PowerOptions Reply Brief at 7, citing DOER Brief at 5).

calculating a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months is unclear (PowerOptions Reply Brief at 6). Therefore, PowerOptions argues that customers will be unable to manage their facilities appropriately (PowerOptions Reply Brief at 6). Accordingly, PowerOptions asserts that the Department should reject the Company's demand ratchet proposal (PowerOptions Reply Brief at 8).

ii. Tiered Customer Charges

PowerOptions argues that a tiered customer charge rate structure based on maximum demand is not appropriate for residential or small commercial customers (PowerOptions Reply Brief at 3). In this regard, PowerOptions contends that these customers cannot appropriately adapt or respond to a tiered customer charge structure without having advanced metering, demand meters, or appropriate technology to know when they are reaching their peak use (PowerOptions Reply Brief at 4). Further, PowerOptions maintains that National Grid did not sufficiently demonstrate that using non-coincident peak demand actually reflects a customer's contribution to distribution system costs, and, as such, it is the appropriate tool for charging distribution rates (PowerOptions Reply Brief at 4, citing NECEC Brief at 11, 13).

Moreover, PowerOptions argues that the Company's Phase II proposal removes the link between a customer's energy conservation and seeing reduced charges on the electric distribution bill because a customer must maintain a year of reduced monthly use to drop to a lower tier (PowerOptions Reply Brief at 3). PowerOptions contends that the tiered customer charge proposal risks undermining one of the Commonwealth's energy policy goals of maximum deployment of energy efficiency (PowerOptions Reply Brief at 4, citing DOER Brief at 7). Further, PowerOptions claims that the delay in monetary savings from the implementation of energy efficiency measures inherent in National Grid's tiered customer charge proposal could discourage these investments and impact the Commonwealth's energy goals (PowerOptions Reply Brief at 4). Additionally, PowerOptions asserts that National Grid has not analyzed how the tiered customer charge proposal may affect the achievement of its three-year energy efficiency plan (PowerOptions Reply Brief at 4-5, citing DOER Brief at 7).

Finally, PowerOptions maintains that the Company's proposal is not consistent with the Department's "standard of review" (PowerOptions Reply Brief at 3). Based on all of these reasons, PowerOptions asserts that the Department should reject the Company's tiered customer charge proposal (PowerOptions Reply Brief at 3, 5).

iii. Seasonal Rate Design

PowerOptions supports the Attorney General's seasonal rate design proposal (PowerOptions Reply Brief at 5). PowerOptions maintains that it is easier for customers to understand than the Company's Phase II proposal and enables customers to respond to price signals (PowerOptions Reply Brief at 5). PowerOptions argues that there is a much stronger correlation between peak-season energy consumption and peak demand than the Company describes (PowerOptions Reply Brief at 5, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Thus, PowerOptions maintains that the Attorney General's seasonal rate design proposal links distribution prices to summer distribution peaks (PowerOptions Reply Brief at 5). According to PowerOptions, the seasonal rate design proposal is cost-based, results in reasonable bill impacts, is simple and understandable, improves efficiency and cost causation, and therefore, meets the Department's rate design goals (PowerOptions Reply Brief at 5, citing NECEC Brief at 30).

g. Company

i. Overview

National Grid argues that the appropriate regulatory forum to determine rate design is in a general rate case, based on the revenue requirement and cost studies used to establish "just and reasonable" rate design (Company Reply Brief at 83-84). According to the Company, its rate structure should consist of customer charges, demand charges, and consumption charges that are reflective of customer-related, demand-related and consumption-related costs, respectively (Company Reply Brief at 84). National Grid contends that its proposal is "the first step in a process towards an optimal rate design, which would include both customer and demand charges for each rate class" (Company Brief at 214).

Moreover, the Company maintains that its proposed rate design properly balances the Department's rate design goals: efficiency, simplicity, continuity, fairness, and earnings stability (Company Brief at 202, citing Exh. NG-PP-1, at 29; Company Brief at 211, 213-214). According to the Company, its rate design: (1) produces the desired revenue for each rate class determined in its allocation process; (2) generates revenue that is reasonably stable and predictable while reflecting cost-causation principles; (3) reflects the cost to serve and to ensure adequate revenue to the utility; (4) mitigates extreme bill impacts on customer groups; and (5) results in equalized rates of return amongst all rate classes pursuant to § 94I (Company Brief at 202, citing Exh. NG-PP-1, at 46-47). Therefore, the Company asserts that the Department should approve the Company's proposed rate design in this case (Company Reply Brief at 84).

The Company explains that its primary objective in its rate design proposal is customer equity and to design rates that reflect the actual relative cost to serve each customer (Company

Brief at 203, citing Exh. NG-PP-1, at 23; Company Reply Brief at 83). However, the Company argues that there are limitations in establishing the cost to serve customers and the ability to design rates that recover those costs (Company Brief at 212). In particular, National Grid contends that costs are determined for groups of homogeneous customers with similar cost-causation attributes, not for individual customers (Company Brief at 212, citing Exhs. NG-PP-1, at 39-41; AG-12-2). Further, the Company claims that the Department's rate design goals of simplicity, continuity, and earnings stability often lessen the cost-basis in rate design implementation (Company Brief at 212). Additionally, the Company maintains that it considers the cost and availability of meters in designing rates (Company Brief at 212).

The Company supports transparent and efficient rate designs that provide sufficient revenue to support the distribution system, motivate the appropriate behaviors, and assure fairness and equity among customers (Company Brief at 213). According to National Grid, both DG and non-DG customers impose demand on the distribution system and its associated services (Company Brief at 213). However, the Company asserts that distribution service provided to DG customers is being paid for, in whole or in part, by all customers through revenue decoupling and net metering credits[304] (Company Brief at 213). In this regard, National Grid notes that it recovers the bulk of distribution service costs through the volumetric portion of distribution rates (Company Brief at 213). Further, the Company contends that net metering allows DG customers to zero out bills and to build credits towards their cost for future electricity consumption (Company Brief at 214). The Company contends that this policy has enabled many customers to

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304 The Company reports that net metering caps are over-subscribed, and it provided approximately $64 million of net metering credits to DG customers in 2015 (Company Brief at 215, citing Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3; Tr. 7, at 1043)

avoid payment for their use of the distribution system (Company Brief at 214). Therefore, the Company maintains that the current DG landscape and its rate design creates a growing cost-shift within the Company's service territory, while providing little benefits (Company Brief at 213-215, citing Exh. NG-PP-Rebuttal-1, at 37).

Finally, the Company argues that the price for distribution service should reflect the value and true cost of the service, and customers' bills should reflect each customer's demand for such service (Company Brief at 213). According to National Grid, current rate design does not properly attribute costs caused by customers with DG facilities to those customers, but its rate design proposal appropriately addresses cost responsibility for DG customers (Company Reply Brief at 83-84, 212). The Company contends that if rate design is not based on cost causation, customers that do not use DG facilities are cross-subsidizing those customers with DG facilities (Company Reply Brief at 83, 212).[305] Further, National Grid claims that the Limited Intervenors are employing delay tactics that ignore the impact on rates and cost recovery caused by the rapid development of DG facilities in Massachusetts (Company Reply Brief at 83).

ii. Demand Ratchets

National Grid argues that those opposing the Company's demand ratchet proposal do not dispute the ratemaking objective of demand ratchets, but rather, oppose the demand ratchets' effect on energy efficiency, solar DG, and storage (Company Brief at 226; Company Reply Brief

305 According to the Company, it collects most of its costs through usage charges (Company Reply Brief at 84). The Company contends that the usage of a customer with a DG facility behind-the-meter may drop or vary from the baseline used to establish rate design (Company Reply Brief at 84). Therefore, the Company maintains that the relationship between cost incurrence and revenue collection is broken and the recovery of costs is shifted to other customers (Company Reply Brief at 84).

at 92). The Company asserts that such opposition lacks merit (Company Brief at 227; Company Reply Brief at 93).

In particular, National Grid rejects any arguments that a demand ratchet delays payback periods for energy efficiency and demand reduction investments, and the Company instead notes that its demand ratchet analysis shows little impact on customer savings from the implementation of energy efficiency because approximately 70 to 75 percent of energy efficiency savings result from reductions in kWh use (Company Brief at 227, citing Exh. NG-PP-Rebuttal-1, at 28; Company Reply Brief at 93). Further, National Grid maintains that the record demonstrates that a demand ratchet has little impact on a customer installing energy efficiency or demand reduction technologies (Company Brief at 227, 228; Company Reply Brief at 93, 94). According to the Company, it calculated a $200 to $400 reduction, from total savings ranging from $26,000 to $57,000, in the first year of an energy efficiency investment, due to the demand ratchet (Company Brief at 227, citing Exh. DPU-15-16, Att. at 3-4; Company Reply Brief at 93). Moreover, the Company argues that with or without the demand ratchet, the customer will accumulate all of the annual savings associated with energy efficiency investments after the first investment year (Company Brief at 227-228; Company Reply Brief at 93-94).

Regarding the installation of a demand reduction investment (i.e., DG or storage), the Company maintains that customer savings on an installation that reduces 50 percent of kW and kWh billing determinants reduced savings by 2.6 percent for the first year (from approximately $205,800 to $193,800) as a result of the demand ratchet (Company Brief at 228, citing Exh. DPU-15-16, Att. at 5; Company Reply Brief at 94). Therefore, National Grid contends that demand ratchets will not cause a disincentive to invest in energy efficiency or demand reduction technologies (Company Brief at 228; Company Reply Brief at 94).

Further, the Company argues that a demand ratchet is reasonable and appropriate for Rate G-2 and Rate G-3 customers because it will assess demand charges based upon each customer's maximum demand during the year (Company Brief at 208; Company Reply Brief at 92). The Company notes that its system was designed and built to accommodate maximum aggregate demand of all customers at a single point in time (Company Brief at 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Thus, the Company asserts that its proposal will better reflect a customer's contribution to coincident demand, and it will result in cost recovery more reflective of the costs that are incurred to serve that customer (Company Brief at 208, 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Consequently, National Grid asserts that it has demonstrated that the demand ratchet for Rates G-2 and G-3 is reasonable, and that its proposal should be approved (Company Brief at 228; Company Reply Brief at 94).

iii. Tiered Customer Charges

National Grid argues that its Phase II rate design proposal is a reasonable change in rate structure to move rates for residential and small commercial customers toward the recovery of customer-related and demand-related costs to serve (Company Brief at 225; Company Reply Brief at 91). According to the Company, a higher customer charge for higher-use customers is a reasonable proxy to recover the higher demand-related costs imposed on the distribution system by these customers (Company Brief at 225; Company Reply Brief at 91). The Company asserts that its proposal is consistent with the Department's rate structure goals and objectives, and, therefore, it should be approved (Company Brief at 225; Company Reply Brief at 91).

According to the Company, a distribution system is sized and constructed to accommodate the maximum demand on the system at a single point in time, and, once constructed, distribution system costs are fixed in nature (Company Brief at 217, 218, citing Exhs. NG-PP-1, at 33, 38; Company Reply Brief at 85, 86). The Company maintains that a customer's monthly maximum kWh use during a 12-month period reflects the customer's contribution to total system demand and should be the basis for the customer's cost responsibility in rate design instead of a customer's monthly or annual kWh consumption (Company Brief at 217, 218, citing Exh. NG-PP-1, at 38-39; Company Reply Brief at 85, 86). Therefore, the Company contends that its Phase II rate design proposal better aligns the recovery of fixed distribution system costs than the current single customer charge for these rate classes and results in a more equitable contribution to costs by all customers on the basis of their size (Company Brief at 217, 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 85, 86). Further, National Grid argues that a reduction in energy consumption does not necessarily result in a corresponding reduction in distribution costs (Company Brief at 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 86). According to the Company, the Phase II rate design proposal is a reasonable proxy for a rate structure in which a fixed customer charge recovers the customer related cost to serve each customer and a demand charge based on customer size recovers capacity-related costs (Company Brief at 217, citing Exh. EFCA 1-1; Company Reply Brief at 85).

The Company disagrees with the argument that the adoption of the tiered customer charge would be inconsistent with § 141 (Company Brief at 222, citing Low Income Network Brief at 17-26; Vote Solar Brief at 22-23; Company Reply Brief at 88, citing Low Income

Network Reply Brief at 5-7; NECEC Reply Brief at 12-13; Vote Solar Reply Brief at 11-13). The Company argues that interpreting the statue to ban any rate design that would affect existing incentives for DG and energy efficiency is not consistent with the plain language of that statute (Company Brief at 222; Company Reply Brief at 88). Rather, according to the Company, a reasonable reading of the statutory language is that the Department is required to consider the impacts of the Company's proposed rate design along with the increased incentives that are provided to energy efficiency and on-site generation (Company Brief at 222 (emphasis in original); Company Reply Brief at 88-89). The Company maintains that the Department must balance the various interests (i.e., rate design and incentives for energy efficiency and DG), which the Company advocates for in its rate design proposals (Company Brief at 222; Company Reply Brief at 89).

Further, in response to the argument that the tiered customer charges do not reflect the demand-related costs that individual customers put on the system and that they do not consider the timing of the customer's non-coincident peak and peak demand, the Company asserts that existing demand charges are based on a customer's maximum demand (Company Brief at 220; Company Reply Brief at 87). For example, the Company argues that demand charges for C&I customers are assessed on the customer's maximum kW because it represents the customer's potential to contribute to the capacity requirements of the distribution system (Company Brief at 220-221, citing Exh. NG-PP-Rebuttal-1, at 14; Company Reply Brief at 87, citing Exh. NG-PP-Rebuttal-1, at 14). Therefore, the Company asserts that a demand charge designed to recover demand-related distribution costs billed to the customer on maximum monthly demand is not new or unreasonable (Company Brief at 221; Company Reply Brief at 87).

Further, in response to the argument that the tiered customer charge proposal is not an improvement over the current rate design, the Company argues that its detailed analysis refutes the claim (Company Brief at 223, citing Exh. NG-PP-Rebuttal-2; Company Reply Brief at 89 citing Exh. NG-PP-Rebuttal-2). According to the Company, the analysis comparing bill charges resulting from: (1) the existing rate design; (2) the proposed residential Phase I rate design; (3) the proposed residential Phase II rate design reflecting tiered customer charges; and (4) a rate design that includes separate customer and demand charges, demonstrates that, for both high- and low-load factor customers, its Phase II proposal charge more closely approximates the rates based on separate customer and demand charges (Company Brief at 223, citing Exh. NG-PP-Rebuttal-1, at 12; Company Reply Brief at 89). In addition, National Grid argues that its Phase II rate design proposal does not produce monthly bills that are significantly different from those under either the current rate structure or its proposed Phase I rate design (Company Brief at 223; Company Reply Brief at 89). Therefore, the Company asserts that its Phase II proposal fulfills the Department's rate continuity goal (Company Brief at 223; Company Reply Brief at 89).

National Grid also rejects any arguments that its proposed tiered customer charge structure is confusing and provides insufficient price signals (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). The Company contends that such arguments are contradictory to the notion that customers demand more time varying rates (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). In this regard, the Company argues that although its proposal is based on the concept that customer demand underlies the basis for the tiered customer charge, the actual structure of the rates (i.e., a customer charge and a per-kWh rate) does not change (Company Brief at 224-225, citing Exh. NG-PP-Rebuttal-1, at 30; Company Reply Brief at 90-91).

Moreover, while National Grid acknowledges that customers might not be familiar with the concept of demand, the Company argues that customers understand the implications on the distribution system resulting from changes in electricity consumption (Company Brief at 224, n.44, citing docket D.P.U. 10-82, evaluation report of the Company's Smart Energy Solutions Program; Company Reply Brief at 90 n.20). Further, the Company claims that its outreach and education program will resolve any customer confusion about its Phase II rate design proposal (Company Brief at 225; Company Reply Brief at 91). In particular, the Company maintains that it proposed a six month delay in its Phase II rate design effective date "to educate customers on the reason behind and determination of the tiered customer charges, including changes to their bills and ways to reduce usage to take advantage of tiers with lower customer charges" (Company Brief at 225, citing Exh. NG-PP-Rebuttal-1, at 31; Company Reply Brief at 91).

iv. Seasonal Rate Design

National Grid opposes the alternative seasonal rate design proposal recommended by the Attorney General and others, as the Company claims that there is no cost basis for the 15-percent differential between summer and winter rates (Company Brief at 224; Company Reply Brief at 90; see Attorney General Brief at 137; Attorney General Reply Brief at 72, 76; Acadia Center Brief at 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30; NECEC Reply Brief at 3, 6, 10, 12, 13). According to the Company, "while there is little data identifying a peak load during the non-summer months of October through May, many feeders may experience non-summer peak demands that are very close to their summer peak demand" (Company Brief at 223-224, citing Exh. VS-2-12; Company Reply Brief at 89). Further, the Company contends that a summer-peaking feeder may become winter peaking during extremely cold weather, and that transition reduces the differences between summer and winter peak demands (Company Brief at 224; Company Reply Brief at 89-90). Further, National Grid claims that increasing solar generation affects summer demand far greater than winter demand, further increasing the probably of peak loads shifting from the summer months to the winter months in the future (Company Brief at 224; Company Reply Brief at 90). Therefore, the Company argues that "a system-wide reduction in coincident peak demand may not result in a commensurate reduction in actual or forecasted peak demand for each feeder" (Company Brief at 224; Company Reply Brief at 90). Finally, the Company asserts that setting a summer rate 15 percent higher than a winter rate will produce arbitrarily higher net metering credits (Company Brief at 224; Company Reply Brief at 90).

6. Analysis and Findings

In ruling on the 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. 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. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.

a. Demand Ratchets

DOER, EFCA, AIM and TEC, and PowerOptions, oppose the Company's demand ratchet proposal. The Company previously proposed to implement demand ratchets, and the Department denied the Company's request. Massachusetts Electric Company, D.P.U. 85-146, at 68-69 (1986). In denying the demand ratchet proposal, the Department found that demand ratchets can, in an uneconomic manner, provide no incentive to reduce demand beyond the class or system peak and little incentive to reduce kWh use. D.P.U. 85-146, at 69. Moreover, we determined that a demand ratchet distorts the price signal to the customers and discourages customers from investing in load control equipment that would otherwise be cost-effective. D.P.U. 85-146, at 68; see also D.P.U. 84-145-A at 125. Further, the Department has found that demand ratchets are inappropriate because they distort incentives to conserve electricity and could unfairly impose higher costs on certain customers. Western Massachusetts Electric Company, D.P.U. 94-101/95-36, at 50 (1995); D.P.U. 92-78, at 188; Western Massachusetts Electric Company, D.P.U. 86-280, at 196 (1987); D.P.U. 84-25, at 199.

Further, the Company did not present any particularly compelling argument that would persuade the Department to alter its precedent on this matter.[306] In particular, the Department finds that the Company failed to provide sufficient evidence to demonstrate that a customer would have any incentive to reduce their demand after it reaches its annual peak demand. Therefore, we find that the Company's proposed demand ratchet is inconsistent with the aforementioned Department precedent, as well as the Department's goals of efficiency and fairness. As such, the Company's demand ratchet proposal is denied. Accordingly, the Department directs the Company in its compliance filing to revise its proposed demand charges for Rates G-2 and G-3 to eliminate the demand ratchet component. Instead, the Company shall design the demand rates consistent with the definition of billing demand found in its currently effective Rates G-2 and G-3 tariffs, M.D.P.U. Nos. 1152 and 1153 (respectively for MECo) and M.D.P.U. Nos. 526 and 527 (respectively for Nantucket Electric).

b. Tiered Customer Charges

National Grid's tiered customer charge proposal is premised on the Company's position that under its current rates there is a shift in cost recovery from DG customers to non-DG customers (Exh. NG-PP-Rebuttal-1, at 53). The tiered customer charges are designed to mitigate that cost-shift by using a customer's highest monthly energy use as a proxy for that customer's peak demand, thereby employing a rate design that captures the cost that a customer imposes on

[306] The Department recognizes that it accepted demand ratchets as a reasonable resolution of the issue of undue discrimination in allowing standby rates, but only in the context of a Settlement Agreement between NSTAR Electric, DOER, AIM, CLF, the Joint Supporters and SEBANE. NSTAR Electric Company, D.T.E. 03-121, at 42 (2004). In approving the Settlement Agreement, the Department's decision in that proceeding was not intended to represent a fully litigated review on the merits resulting in a wholesale change in rate making policy. D.T.E. 03-121, at 42 n.16.

the distribution system from the customer's individual peak demand (Exhs. NG-PP-1, at 32-35; NG-PP-Rebuttal-1, at 10; DPU-9-14). The Attorney General, DOER, the Low Income Network, the Limited Intervenors, and PowerOptions oppose the Company's tiered customer charge proposal.

The Company purports that "DG customers <u>may</u> contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers" (emphasis added) (Exh. NG-PP-1, at 28). The Company has not quantified the amount of costs attributable specifically to DG customers and has not quantified the distribution system benefits associated with DG customers in its service territory (Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; LI-1-10, at 1; Tr. 5, at 620). Other than quantifying net metering credits and citing to current rate design, the Company did not substantiate its cost-shift assumption with reasonable analysis and quantitative record evidence (Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3, Att.). As such, the Department is not persuaded that a cost-shift from DG customers to non-DG customers, in fact, exists. Therefore, we find that the basis of the Company's tiered customer charge proposal is not sufficiently supported.

Further, § 141 states, in part: "[i]n all decisions or actions regarding rate designs, the [D]epartment 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." The Company's tiered customer charge proposal shifts cost recovery away from the volumetric, per-kWh charges, causing kWh rates to decrease (Exh. NG-PP-1, at 32). As volumetric, per-kWh rates decrease, customers' incentives to install energy efficiency and on-site generation diminish as potential savings are lower and net metering credits are lower. Further, the Company failed to provide evidence regarding the impact of its tiered customer charges on energy efficiency, compliance with the three-year energy efficiency plan, and incentives to lower demand (Exh. DOER-2-18; Tr. 5, at 634). Moreover, although pricing distribution service on demand use may support the cost-to-serve principle, it is not the best rate structure to promote energy efficiency. D.P.U. 10-70, at 332.

The Company's tiered customer charge proposal and demand ratchet proposals are similar in operation. Similar to the demand ratchet proposal, the Department finds that the Company's tiered customer charge proposal provides no incentive to lower demand and electricity use below the highest level within a tier. Additionally, the tiered customer charges distort incentives to conserve electricity, may unfairly impose higher costs on certain customers, and discourage customers from investing in cost-effective energy efficiency. D.P.U. 94-101/95-36, at 50; D.P.U. 92-78, at 188; D.P.U. 86-280, at 196; D.P.U. 85-146, at 68-69; D.P.U. 84-145-A, at 125; D.P.U. 84-25, at 199.

Next, the Department addresses whether the Company's tiered customer charge proposal meets our rate design goal of simplicity. National Grid's tiered customer charge proposal is a transition toward mandatory demand charges for residential and small C&I customers (Exh. NG-PP-Rebuttal-1, at 10-11). However, the Company failed to establish that demand charges are understandable by residential and small C&I customers. Additionally, although the Company planned to implement an outreach and education plan, by the close of the record it had not developed a detailed customer outreach and education plan at this time (Exh. VS-2-6; see Exhs. NG-PP-1, at 45; DPU-9-16). Further, the Company's proposal, including residential demand charges, is not a mandatory residential rate design used by any state-regulated utility in the country (Exh. DPU-12-2; Tr. 5, at 638-641, 654-657). The Department is concerned that the Company has not determined its customers' tolerance and acceptance of a significant change in rate design, and therefore, has not presented adequate strategies to ensure that its customers will understand the tiered customer charge proposal.

Further, under the Company's proposal, customers lack the ability to monitor their electricity consumption throughout the month in real time (Tr. 7, at 1186-1187). Under the Company's inclining block rate structure, customers were not able to monitor their use to ascertain when or if it would be high enough to be billed at the tail block rate (Tr. 7, at 1186-1187). Further, customers will experience a lag between actual consumption, and the availability of the data and resulting customer charge tier (Exh. VS-2-7). Thus, customers do not have the equipment to easily monitor electricity consumption in real time and would be unaware if they were about to reach a new maximum monthly kWh use that would increase their customer charge. Accordingly, the Department finds that the Company's tiered customer charge proposal fails to meet the Department's rate design goal of simplicity.

Next, the Department addresses whether the Company's tiered customer charge proposal meets our rate design goal of efficiency. In support of its tiered customer charge proposal, National Grid provided analysis of approximately 12,300 residential and 300 small C&I load research customers' relationship between maximum annual kWh use and maximum demand use and concluded from this analysis that a customer's maximum kWh use can be used to approximate their demand, as measured in kW (Exhs. NG-PP-1, at 41; NG-PP-10). The Company reached this conclusion based on the fact that the maximum billed use explained more than 50 percent of the variation in maximum hourly load, as measured by the R-squared[307] value of 0.6093 for residential and 0.7512 for small C&I (Exhs. NG-PP-1, at 41; NG-PP-10; WP-NG-PP-3; Tr. 5, at 687-689). However, the Company was unsure if it would have proposed tiered customer charges if the R-squared value was less than 0.5 (Tr. 5, at 692). In similar analyses comparing customers' maximum annual kWh use and maximum demand within each of the four proposed customer charge tiers, only one R-squared value was greater than 0.5 (Exh. DPU-9-8; Tr. 5, at 637-638).[308] Therefore, the Department finds that the Company's tiered customer charge proposal is inadequate for serving as a proxy for a customer's contribution to maximum demand (see Exh. AG-SJR-1, at 19). Additionally, the Company's current rate design is more reflective of the cost to serve and a better indicator of customer's maximum demand than is the Company's tiered customer charge proposal (Exhs. AG-SJR-20-30; EFCA-TW/MW-1, at 27-29; NECEC-RTB-1, at 19-20; DPU-9-8, Att.; DPU-NECEC-1-4; DPU-NECEC-1-5, Att.; RR-DPU-27, Att.).

For all of these reasons, the Department finds that the Company's tiered customer charges do not meet our rate design goals of simplicity and efficiency, and do not provide strong signals to consumers to decrease energy consumption in consideration of price and non-price,

[307] As noted, R-squared is a statistical measure of how close the data are to the fitted regression line and measures the strength of a relationship (Exh. DPU-15-9; Tr. 8, at 1218). In general, the higher the R-squared, the better the model fits the data (Exh. DPU-15-9). A R-squared value of one means that the model explains all the variability of the data, and a R-squared value of zero means that the model explains none of the variability of the data (Tr. 5, at 636).

[308] For residential customers in Tiers 1, 2, 3, and 4, the analyses showed R-squared values of: 0.1911, 0.1352, 0.1134, and 0.4587, respectively (Exh. DPU-9-8, Att.). For Rate G-1 customers, the R-squared values for Tiers 1, 2, 3, and 4 were: 0.2306, 0.0576, 0.3617, and 0.5727, respectively (Exh. DPU-9-8, Att.).

social, resource, and environmental factors. Accordingly, we decline to accept the Company's Phase II, tiered customer charge rate design proposal.[309] The Department addresses rate design for Rates R-1, R-2, and G-1 in the Rate-by-Rate section, below.

c. Seasonal Rate Design

In the alternative to the Company's tiered customer charge proposal, the Attorney General proposed a seasonal rate design for Rates R-1 and R-2. This proposal is supported by Acadia Center, NECEC, and PowerOptions (Attorney General Brief at 134-135; Acadia Center Brief at 2, 17-18; NECEC Brief at 29-30; PowerOptions Reply Brief at 5).

The Department stated that it would consider seasonally differentiated rates, as well as other dynamic pricing alternatives to inclining block rates. D.P.U. 10-70, at 330. In considering "other dynamic pricing alternatives" in an investigation into time varying rates, the Department declined to implement time varying distribution rates. Time Varying Rates, D.P.U. 14-04-B at 13-14 (2014). We see no reason to deviate from that position here.

Moreover, the Attorney General's seasonal rate design proposal is only a slight improvement in cost-effectively collecting the cost to serve the distribution system compared to the Company's Phase I proposal (Exh. AG-SJR-1, at 30). For example, in an analysis of 12,056 residential customers comparing the cost of service and the Attorney General's proposed distribution bill, the seasonal rate design improves the relationship to cost increases by 0.004 R-square from 0.271 to 0.281, and the average variance between costs and revenues from 53 percent to 52 percent (Exhs. AG-SJR-1, at 30; AG-SJR-12). Annual bill impacts improve

[309] Because the Department declines to adopt the Company's tiered customer charge proposal, we will not address continuity (i.e., bill impacts). In the Rate-by-Rate section, below, the Department considers continuity when determining each rate class's rate design.

slightly from a range of increases of 20 percent to 48 percent to 22 percent to 45 percent (Exh. AG-SJR-1, at 30). Further, residential customers already experience rate changes on March 1, May 1, and November 1 (Tr. 7, at 1182). Seasonal rates would establish additional mandatory rate changes on July 1 and October 1 (see Exh. AG-SJR-1, at 30). The Department finds that a "slight improvement" in rate design compared to the Company's Phase I proposal is outweighed by the potential for additional customer confusion and reduced simplicity in the Company's Phase I rate design. Based on the foregoing, the Department declines to adopt the Attorney General's seasonal rate design proposal for Rates R-1 and R-2. The Department addresses rate design for Rates R-1 and R-2 in the Rate-by-Rate section, below.

d. Inclining Block Rates

The Department finds that the Company's proposed flat rate structure for all rate classes is consistent with the rate design policy developed in recent base rate cases. D.P.U. 14-150, at 400; D.P.U. 13-90, at 250; D.P.U. 13-75, at 358-361; D.P.U. 12-25, at 468-469. As such, the Department approves the elimination of inclining block rates. Regarding the proper level to set the customer charge and volumetric rates for each residential and C&I rate class, the Department will make this determination on a rate class by rate class basis, balancing our rate design goals.

E. Low Income Discount

1. Introduction

a. Background

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low income customers comparable to the low income discount rate received off the total bill for rates in effect prior to March 1, 1998. See Expanding Low Income Customer

Protections and Assistance, D.P.U. 08-4, at 36 (2008). In the Company's last base rate proceeding, the Department made modifications to the application of the low income discount and established a low income discount of 25 percent applied to a Rate R-2 customer's total bill. D.P.U. 09-39, at 429-432.

The Company states that the current average low income monthly discount for a 500 kWh use customer is $30.04 or 28.8 percent (Exh. LI-1-5, at 2 (Supp.)). According to the Company, the monthly discount consists of the 25 percent total bill discount approved in D.P.U. 09-39 plus the discount from the Rate R-2 Energy Efficiency Reconciling Factor ("EERF") being less than that assessed to Rate R-1 customers (Exh. LI-1-5, at 2-3 (Supp.)).

b. Low Income Network's Recommendation

Pursuant to the second clause of § 141,[310] the Low Income Network initially recommended that the Department increase the average low income monthly discount from 28.8 percent to 35 percent (Exh. LI-JH-1, at 18). The Low Income Network's initial recommendation was based on the purported increase in costs associated with (1) renewable portfolio standard ("RPS") solar carve out; (2) RPS except solar carve out; (3) net metering recovery surcharge ("NMRS"); (4) long-term renewables contracts; (5) utility owned solar; and (6) Smart Grid pilots (Exhs. LI-JH-1, at 17-18; LI-1-5). According to the Low Income Network, these costs are related to the growth of on-site generation, and the increase in these costs has resulted in higher bills for low income customers (Exh. LI-JH-1, at 17-18, citing Exh. LI-1-5 (Supp.) & Att.). Therefore, the Low Income Network recommends an increase in the low

[310] See n.300 above.

income discount to fully compensate low income customers for these increased costs (Exh. LI-JH-1, at 18).

Subsequently, on brief, the Low Income Network modified its recommendation for an increase of the low income discount from 25 percent to 33 percent (Low Income Brief at 23-24). The Low Income Network's revised calculation is based on the purported increase in costs associated only with (1) RPS solar carve out; and (2) NMRS (Low Income Brief at 23-24; Exhs. DPU-LI-1-5; WP-DPU-LI-4; WP-DPU-1-5). The Low Income Network acknowledges that only these two categories of costs are related to the growth of on-site generation (Low Income Brief at 23).

c. Company's Alternative Proposal

In response to the Low Income Network's proposal, the Company proposes to maintain the low income discount at its current level of 25 percent, but to exempt Rate R-2 customers from being charged for on-site generation costs that the Department concludes should be avoided by this customer group (Exh. NG-PP-Rebuttal-1, at 64). For instance, if the Department concludes that Rate R-2 customers should not pay for all or any part of the Company's cost of complying with the RPS that is a component of basic service rates, whether it be the solar carve-out and/or the non-solar carve out cost, the Company would exclude those costs from the RPS component of the low income basic service rates and allocate the estimate of those costs to all other Basic Service customers (Exh. NG-PP-Rebuttal-1, at 64).[311] Further, National Grid

[311] National Grid notes, however, that removing all or any part of the Company's cost of complying with the RPS from basic service rates for low income customers creates a lower basic service rate with which competitive suppliers would have to compete (Exh. NG-PP-Rebuttal-1, at 66). According to the Company, approximately 52 percent

states that with respect to net metering costs, the Company could alter the manner by which it recovers net metering credits paid for excess generation (Exh. NG-PP-Rebuttal-1, at 65). More specifically, in designing the NMRS factors, the Company proposes to exclude Rate R-2 in the allocation of the balance of the NMRS reconciliation and the amount would be recovered from all other customers (Exh. NG-PP-Rebuttal-1, at 65). Rate R-2 customers would therefore not be billed an NMRS (Exh. NG-PP-Rebuttal-1, at 65).

The Company's alternative proposal does not include the impact of displaced distribution revenue, which still would be recovered through the Company's RDM (Exh. NG-PP-Rebuttal-1, at 65). According to the Company, its alternative proposal is intended to simplify the application of the concept presented by the Low Income Network and has the added benefit of creating transparency in the amount of net metering costs recovered from non-low income customers (Exh. NG-PP-Rebuttal-1, at 65).

2. Positions of the Parties

a. The Low Income Network

The Low Income Network provided several reasons for its recommended increase to the low income discount. First, the Low Income Network argues that the scale of on-site generation[312] is now "substantial," with installed capacity from distributed generation on the Company's system exceeding 15 percent of the Company's peak load (Low Income Network

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of Rate R-2 customers currently receive electricity supply from a competitive supplier (Exh. NG-PP-Rebuttal-1, at 66).

[312] The Low Income Network asserts that the Department should determine the meaning of the term "on-site generation," in the context of § 141 (Low Income Network Brief at 19). In this regard, the Low Income Network argues that "on-site generation" is used in a "common-sense manner" that encompasses only solar and other renewable energy production on the site of an end-use customer (Low Income Network Brief at 19 n.65).

Brief at 19, 20-21, citing Tr. 7, at 1003; RR-LI-2). Second, the Low Income Network contends that the scale of on-site generation has resulted in a six-percent increase in total bills for low income customers, thereby impacting the affordability of electric service for low income customers (Low Income Network Brief at 19).[313] In this regard, the Low Income Network claims that low income households already do not have sufficient income to meet the high cost of living in Massachusetts, and that the burden of paying for electricity is higher on low income households than other customers (Low Income Network Brief at 21-22). Thus, according to the Low Income Network, a six-percent increase in bills as a result of the scale of on-site generation is particularly onerous for low income customers (Low Income Network Brief at 22).

Third, the Low Income Network argues that the record supports an increase of the low income discount to 33 percent, as this level of discount takes into account costs associated with the RPS solar carve out and the NMRS and will represent a "fully compensating adjustment" to the low income discount rate (Low Income Network at 19, 22-23, citing Exhs. LI-JH-1, at 17-18; NG-PP-Rebuttal-1, at 55; LI-1-5; DPU-LI-1-3; DPU-LI-1-5; Tr. 7, at 1034-1036). According to the Low Income Network, the Company does not dispute the Low Income Network's calculations that produce a 33-percent discount for the low income discount (Low Income Network Brief at 24; Low Income Network Reply Brief at 6).

Finally, the Low Income Network argues that the Company's alternative proposal would violate § 141 because the method of providing a "fully compensating adjustment" would require low income customers on competitive supply to find a competitive supplier that is willing to offer a similar discount to that being offered by the Company (Low Income Network Brief

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313 The Low Income Network states that this increase is inclusive of distribution charges and basic service or competitive supply rates (Low Income Brief at 19).

at 24-25). According to the Low Income Network, nothing in the record suggests that there are any such competitive suppliers (Low Income Network Brief at 25, citing Tr. 7, at 1040). Moreover, the Low Income Network claims that the Company fails to explain how its approach would address current impacts on affordability due to increased on-site generation (Low Income Reply Brief at 6). For all of these reasons, the Low Income Network asserts that the Department should reject the Company's proposal (Low Income Network Brief at 25).

b. Company

The Company argues that its rate design proposals are meant to avoid the current and future scale of energy efficiency and on-site generation from having any impact on the affordability of electricity for all customers, not just low income customers (Company Brief at 222-223). As a result, National Grid claims that its rate design proposals would obviate the need for what the Company considers a reconciling mechanism to address the "fully compensating adjustment" to the low income discount (Company Brief at 223).

Further, the Company submits that the Department is not required to order an electric distribution company to automatically increase its low income discount to compensate for the cost of on-site generation billed through rates to low income customers, but rather the Department should consider the magnitude of those costs on the affordability of electric service to this group of customers in light of such costs paid by all customers (Exh. NG-PP-Rebuttal-1, at 54).[314] Nevertheless, the Company acknowledges that the cost of on-site generation has

[314] With respect to the scale of on-site generation, the Company submits that if the Department is contemplating any "impact on affordability for low income customers" from "the scale of on-site generation," it should limit its analysis to consider on-site generation of any technology with a nameplate capacity of 60 kW or less (Company Brief at 222-223 at n.43).

increased over the past several years for all customers and may result in an additional burden to low income customers in being able to pay their electric bills. (Exh. NG-PP-Rebuttal-1, at 54-55).

The Company does not directly address the Low Income Network's revised recommendation to increase the low income discount to 33 percent. However, the Company notes that in order to arrive at the Low Income Network's original recommended discount of 35 percent, without changing the rates charged to Rate R-2 customers and in consideration of the EERF, the current 25 percent low income discount would need to be 31.6 percent (Exh. NG-RRP-Rebuttal-1, at 55).

Finally, National Grid expresses concern with the Low Income Network's proposal because, according to the Company, changing the discount percentage would require "an annual re-setting of the percentage reflecting changes in the cost of distributed generation reflected in rates charged to Rate R-2 customers, or else the value of the discount would either be diluted or more generous, depending upon how those costs change over time" (Exh. NG-PP-Rebuttal-1, at 56). The Company submits that in D.P.U. 09-39 the Company's recommendation for a clear discount calculated at 25 percent of the entire bill was intended to avoid resetting a discount rate based on a set of rates in effect at a specific point in time. (Exh. NG-PP-Rebuttal-1, at 56)

3. Analysis and Findings

Pursuant to § 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. Based on our review of the record, the Department finds that on-site generation has grown with an increase in costs from associated incentives (i.e., the RPS solar carve out and the NMRS). The increased costs of these incentives are included in customers' bills, including bills of low income customers (see Exhs. LI-JH-1, at 16-18; NG-PP-Rebutal-1, at 54-55; LI-1-5 (Supp.) & Atts.; Tr. 7, at 1034; RR-DPU-41 & Att.). Thus, low income customers have experienced an increase in bills as a result of the growth of on-site generation. Therefore, pursuant to § 141, the Department finds it appropriate to adjust the Company's low income discount.

As an initial matter, we decline to adopt National Grid's alternative proposal. The Company's proposal appears overly complex and would require competitive suppliers to modify the products that they offer to low income customers. We note that competitive suppliers have not had an opportunity for comment on such a modification.

We find that a fully compensating adjustment to the low income discount would include only the costs associated with the RPS solar carve out and the NMRS, as these costs are directly related to the growth of on-site generation. The Department calculates the incremental increase between 2010 and 2015 for RPS solar carve out and NMRS costs for low income customers to be $50.46, or $4.20 per month.[315] In order to fully compensate low income customers for this increase, as required by § 141, the Department directs the Company in its compliance filing to this Order to increase the low income discount such that the low income discount produces an additional $4.20 in discount for the average low income customer each month, based on all rates that are in effect when the Company's new distribution rates take effect. In order to calculate the

[315] The Department's calculation is based on information in the response to record request DPU-41 and the attachment to the record request. The $50.46 is derived by first multiplying the incremental difference in the two charges for each month by 500 kWh. Second, those monthly totals are summed to arrive at an annual figure. Finally, the annual figure is multiplied by 0.75 to account for the 25 percent low income discount.

revised low income discount, the Company shall base its calculation on a bill for an R-2 customer using 500 kWh per month to an undiscounted bill for that same customer.[316]

The adjusted low income discount will remain in effect until the Company's next base rate case, at which time the Department will determine whether further adjustment is warranted. The Department expects that in their respective next base rate proceedings, all electric distribution companies will file revised rate design proposals for low-income customers that comply with the standard set forth in § 141.

F. Farm Discount

1. Introduction

The farm discount is offered to customers who meet the eligibility requirements for being engaged in the business of agriculture or farming as defined in G.L. c. 128, § 1a. 220 C.M.R. § 11.04(6)(a)[317] (see also Exh. NG-PP-23, at 5 (proposed M.D.P.U. No. 1264)). These customers are eligible for an additional ten percent discount from their distribution service rates. 220 C.M.R. § 11.04(6)(a) (see also Exh. NG-PP-23, at 5 (proposed M.D.P.U. No. 1264)). For

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316 As an illustrative example, the calculation that was provided in response to Record Request DPU-41 would be modified such that the value in column (a), row (1) would be $99.05, which is the undiscounted value in row (2) ($74.29/0.75).

317 Pursuant to 220 C.M.R. § 11.04(6)(a):

> Each [d]istribution [c]ompany shall provide [c]ustomers who meet the eligibility requirements for being engaged in the business of agriculture or farming, as defined in [G.L. c. 128, § 1A], a [ten percent] reduction in the rates to which such [c]ustomers would otherwise be subject. Each [d]istribution [c]ompany shall allocate to other rate classes, as part of a general rate case, the revenue deficiency resulting from the farm discount using an allocation method approved by the Department for the [d]istribution [c]ompany.

rate classes R-1, R-2, R-4, G-1, G-2, and the street lighting rate classes, the Company proposes to recover through the base rate for each rate class, the revenue shortfall in the test year attributable to each rate class from the farm discount (Exhs. NG-PP-1, at 53-54; NG-PP-13, at 1-4, 6; DPU-18-15). The proposed farm discount is included as an increase to revenue to be collected through the Company's proposed rate design and totals $572,833 (Exh. NG-PP-13, at 1-4, 6).[318] No party commented on the Company's proposal.

2. Analysis and Findings

The Department stated in Farm Discounts, D.T.E. 98-47, Letter Order at 6 (November 16, 1998), that gas distribution companies may defer costs associated with the implementation of the farm discount for consideration in a subsequent general base distribution rate case. See also D.P.U. 13-75, at 246. The Department has allowed amortization of the deferred farm discounts over periods consistent with the normalization period used to normalize rate case expense. D.P.U. 15-80/D.P.U. 15-81, at 240; D.P.U. 10-70, at 144; D.P.U. 09-30, at 263; D.T.E. 02-24/25, at 204-205.

The Department finds that the Company's proposed method of recovering the farm discount shortfall for each rate class is inconsistent with the Department's policy regarding farm discounts. The farm discount is a social benefit and as such it should be recovered from all customers. Therefore, the Department rejects the Company's proposal. Rather, we conclude that the Company may defer and recover the farm discount credit balance as an amortization in

[318] For R-1/R-2: $343,797; for R-4: $244; for G-1: $101,730; for G-2: $125,092; and for street lighting: $1,970 (Exh. NG-PP-13, at 1-4, 6). Therefore, $343,797 + $244 + $101,730 + $125,092 + $1,970 = $572,833.

its next base rate case. D.P.U. 15-80/D.P.U. 15-81, at 240; D.P.U. 10-70, at 143-145; D.P.U. 09-30, at 262-263; D.T.E. 98-47, Letter Order at 6.

G. Rate-by-Rate Analysis

1. Introduction

The Department must determine, on a rate class by rate class basis, the proper level at which to set the customer charge and delivery charges for each rate class, based on a balancing of our rate design 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. 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 its goals of fairness with its 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.

2. Rate R-1 and Rate E

a. Company Proposal

Rate R-1 is available to all residential customers in private dwellings, individual apartments, churches, and farms (Exhs. NG-PP-1, at 51; NG-PP-23, at 4-5 (proposed M.D.P.U. Nos. 1264 (MECo) and 576 (Nantucket Electric))). National Grid proposes to increase the monthly customer charge from $4.00 to $5.50 per month for Rate R-1 in Phase I (Exh. NG-PP-1, at 52). The per kWh charge is calculated as the total class revenue requirement less the revenue recovered through the proposed customer charge and the farm discount credit, divided by the rate year kWh deliveries (Exhs. NG-PP-1, at 53; NG-PP-13, at 1).

Rate E is a closed rate only applicable to Nantucket Electric and is applicable to customers who had separately metered space heating, with the remainder of their electricity use metered and billed on Rate R-1 (Exh. NG-PP-1, at 51). Rate E was retained after the merger of New England Electric System and Nantucket Electric to ensure that customers with consumption billed on Rate E were not adversely affected by new distribution rates after the merger (Exh. NG-PP-1, at 51).

The current distribution rates and structure for Rates R-1 and E are identical, except for the cable facilities surcharge billed to all Nantucket Electric customers (Exh. NG-PP-1, at 51; M.D.P.U. No. 551). The Company proposes to terminate Rate E and move these customers onto Rate R-1. The Company also proposes to eliminate the inclining block volumetric charges for the Rate R-1 and Rate E classes, which the Department allowed above (Exh. NG-PP-1, at 50).

b. Analysis and Findings

Initially, the Department evaluates the Company's proposal to combine customers on Rate E with Rate R-1. No party objected to the Company's proposal. The Department finds this proposal to be reasonable because the cost to serve Rate E is similar to the cost to serve Rate R-1. Therefore, the Department directs the Company to terminate Rate E and transfer those customers taking service on Rate E to Rate R-1.

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the R-1 rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate R-1/E is $9.42 (Exhs. NG-PP-1, at 52; NG-PP-2(d) at 22; DPU-33-8, Att. at 22). Based on a review of the embedded costs and the bill impacts on customers, the

Department finds that a proposed monthly customer charge of $5.50 for Rate R-1 is reasonable. The Department directs the Company to set its volumetric charge for Rate R-1 so that the rate classes are charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the volumetric charges for Rate R-1 to collect the remaining class revenue requirement approved in this Order.

3. Rate R-2

a. Introduction

Rate R-2 is a subsidized rate that is available at single locations to all residential customers in private dwellings and individual apartments (Exhs. NG-PP-1, at 51; NG-PP-23, at 6-8, 70-72 (proposed M.D.P.U. Nos. 1265 (MECo) and 577 (Nantucket Electric))). 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 ("LIHEAP") 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-PP-23, at 6, 70 (proposed M.D.P.U. Nos. 1265 (MECo) and 577 (Nantucket Electric))). 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 25-percent discount off of their entire bill (Exh. NG-PP-1, at 52). The Company's RAAF, which operates outside of base rates on a reconciling basis, recovers the low-income discount and arrears forgiven under the Company's Arrearage Management Program ("AMP") (Exh. NG-PP-1, at 47-48).

b. Position of the Parties

i. Low Income Network

The Low Income Network asserts that compared to the other electric utilities in the Commonwealth, the Company has a low rate of adding income-eligible customers onto its AMP (Low Income Network Brief at 2-6, citing Exhs. LI-ML-1, at 5-6; LI-2-2; Tr. 1, at 85 86; RR-LI-3; Low Income Network Reply Brief at 2). The Low Income Network argues that the Company should review its business practices to evaluate their affect AMP enrollment and file a report with the Department within six months of this Order outlining its future actions to improve AMP enrollment (Low Income Network Brief at 2-3, 6; Low Income Network Reply Brief at 2). Further, the Low Income Network maintains that the Company should continue to recover its AMP-related costs on a reconciling basis in the RAAF, consistent with recent Department orders regarding how AMP costs may be recovered (Low Income Network Brief at 3, 6-11, citing D.P.U. 15-80/D.P.U. 15-81, at 244-245; Investigation into Issues Affecting Low-Income Customers, D.P.U. 08-4, at 1-6, 40 (2008); Standards for Arrearage Management Programs for Low-income Consumers, D.T.E. 05-86, at 10-12 (2006); Low Income Network Reply Brief at 2-3). The Low Income Network contends that allowing AMP cost recovery on a reconciling basis is the best solution to meeting the Legislature's intent in requiring the Company to offer an AMP (Low Income Network Brief at 3, 6-11, citing Acts of 2005, c. 140, § 17(a); Low Income Network Reply Brief at 2-3). According to the Low Income Network, the

Company agrees with both of its recommendations (Low Income Network Brief at 3; Low Income Network Reply Brief at 2-3). The Company did not comment on these issues on brief.

c. Analysis and Findings

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the R-2 rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate R-2 is $9.42 (Exhs. NG-PP-1, at 52; NG-PP-2(d) at 22; DPU-33-8, Att. at 22). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that National Grid's proposed monthly customer charge of $5.50 for Rate R-2 is reasonable. The Department directs the Company to set its volumetric charge for Rate R-2 so that the rate class is charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the volumetric charges for Rate R-2 to collect the remaining class revenue requirement approved in this Order.

Moreover, the Department accepts the Low Income Network's recommendations regarding the AMP program (Exh. NG-PP-1, at 48-49; Tr. 1, at 85-86; Tr. 7, at 972-973). Therefore, the Department directs the Company to review its business practices that affect AMP enrollment and within six months of the date of this Order, file a report with the Department outlining its future actions to improve AMP enrollment. The Department allows the Company to continue AMP cost recovery through the Company's RAAF.

4. Rate R-4

a. Company Proposal

Rate R-4 is available to all residential customers in private dwellings, individual apartments, churches, and farms whose use exceeds 2,500 kWh per month for a twelve-month period and who opt for time-of use rates (Exhs. NG-PP-1, at 53; NG-PP-23, at 9-11, 73-75 (proposed M.D.P.U. Nos. 1266 (MECo) and 578 (Nantucket Electric))). The Company does not propose any changes to the Rate R-4 rate structure (Exh. NG-PP-1, at 53).

The Company proposes to decrease the monthly customer charge from $20.87 to $20.00 (Exhs. NG-PP-1, at 53; NG-PP-2(d), at 22). The also Company proposes that the peak and off-peak kWh charges recover the remaining revenue requirement and to set them to produce the same peak to off-peak ratio that is present in the current charges (Exh. NG-PP-1, at 53).

b. Analysis and Findings

Based on the Rate R-4 embedded costs and bill impacts, the Department finds that the Company's proposed customer charge and method for establishing the volumetric charges for Rate R-4, subject to our findings on the farm discount, satisfy continuity goals and produce bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the monthly customer charge at $20.00 and to set its volumetric charges to collect the remaining class revenue requirement approved in this Order using the peak to off-peak ratio that is present in the current charges, truncated at five decimal places.

5. 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 (Exhs. NG-PP-1, at 54; NG-PP-23, at 12-14, 78-80(proposed M.D.P.U. Nos. 1267 (MECo) and 580 (Nantucket Electric))). The Company proposes to maintain the customer charge at $10.00 per month (Exhs. NG-PP-1, at 54). In addition, the Company proposes to maintain the customer charge for unmetered Rate G-1 service at $7.50 per month (Exh. NG-PP-13, at 3). 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 farm discount credit, divided by the rate year kWh deliveries (Exhs. NG-PP-1, at 54; NG-PP-13, at 3). The Company also proposes to increase the minimum charge for G-1 service for all kVA over 25 kVA from $2.08 per kVA to $2.11 per kVA (Exh. NG-PP-13, at 3).

b. Analysis and Findings

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the G-1 Rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate G-1 is $9.95 (Exhs. NG-PP-1, at 54; NG-PP-2(d) at 22). The Company also proposes to maintain the customer charge for unmetered Rate G-1 customers and a modest increase for the minimum charge for Rate G-1 service (Exhs. NG-PP-1, at 54; NG-PP-13, at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that the G-1 Rate, including the proposed changes to the customer charges for metered and unmetered service and the increase to the minimum charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department directs the Company to set its volumetric charge for Rate G-1 so that the rate class is charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the energy charge for Rate G-1 to collect the remaining class revenue requirement approved in this Order.

6. Rate G-2

a. Company Proposal

Rate G-2 is available to C&I and institutional customers who have average consumption greater than 10,000 kWh, but do not exceed 200 kW of demand (Exhs. NG-PP-1, at 55; NG-PP-23, at 15, 81 (proposed M.D.P.U. Nos. 1268 (MECo) and 581 (Nantucket Electric))). National Grid proposes to increase the customer charge for Rate G-2 customers from $16.56 to $25.00 per month (Exhs. NG-PP-1, at 57). Additionally, the Company proposes to increase the per-kW demand charge such that approximately 90 percent of the total revenue requirement is recovered through a combination of the customer charge and the demand charge (Exh. NG-PP-1, at 57). Further, National Grid proposes to increase the demand charge for Rate G-2 customers from $6.00 per kW to $8.50 per kW, and to collect the remainder of the rate class's revenue requirement through a uniform per-kWh charge (Exhs. NG-PP-1, at 57; NG-PP-18, at 7-12). Additionally, the Company proposes a high voltage delivery discount of $0.50 per kW for customers supplied at not less than 2,400 volts and not needing a line transformer (Exhs. NG-PP-1, at 57; NG-PP-14, at 1; NG-PP-13, at 4; NG-PP-23, at 16, 82 (proposed M.D.P.U. Nos. 1268 (MECo) and 581 (Nantucket Electric))).

b. Analysis and Findings

According to the Company's allocated COSS, the embedded customer charge for the G-2 Rate class is $31.83 per month (Exh. NG-PP-1, at 57). Based on a review of the bill impacts on customers, the Department finds that the G-2 Rate, designed with an increase in the monthly customer charge from $16.56 to $25.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department finds that the Company's proposed method for establishing the volumetric charge and demand charge[319] for Rate G-2, subject to our findings on the farm discount, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the demand charge at $8.50 per kW, and the volumetric charge to collect the remaining class revenue requirement approved in this Order, truncated at five decimal places.

7. Rate G-3

a. Company Proposal

Rate G-3 is available to C&I and institutional customers who have average use that exceeds 200 kW of demand (Exhs. NG-PP-1, at 57-58; NG-PP-23, at 18-20, 84-86 (proposed M.D.P.U. Nos.1269 (MECo) and 582 (Nantucket Electric))). The Company proposes to increase the customer charge for Rate G-3 customers from $200.00 to $223.00 per month (Exhs. NG-PP-1, at 57-58). The Company also proposes to eliminate the off-peak per kWh charge and collect the remaining class revenue requirement through only a demand charge (Exh. NG-PP-1, at 58). Further, National Grid proposes to increase the demand charge for Rate G-3 customers from $3.92 per kW to $7.00 per kW (Exhs. NG-PP-13, at 5; NG-PP-18, at 13).

319 The Department disallowed the Company's demand ratchet proposal for Rate G-2 in Section XIII.D.6.a above.

Additionally, the Company proposes a high voltage delivery discount of $0.50 per kW for customers supplied at not less than 2,400 volts and not needing a line transformer and a $6.91 per kW high voltage 115kV delivery discount (Exhs. NG-PP-1, at 57; NG-PP-13, at 5; NG-PP-14, at 1; NG-PP-23, at 19, 85 (proposed M.D.P.U. Nos. 1269 (MECo) and 582 (Nantucket Electric))).

b. Positions of the Parties

EFCA maintains that the Company did not provide evidence showing that a reduced volumetric rate is more efficient to promote energy conservation than the current rate (EFCA Brief at 17, citing Tr. 7, at 1,092). On the contrary, EFCA asserts that a zero per kWh rate sends a strong price signal that electricity conservation is not valuable by reducing incentives for energy efficiency, storage, and other technologies (EFCA Brief at 17, citing Exh. EFCA-MW/TW-1, at 53-54). Accordingly, EFCA recommends that the Department deny the Company's proposed volumetric rate design for Rate G-3 (EFCA Brief at 18).

Further, EFCA opposes the Company's proposed increase to the demand charge from $3.92 per kW to $7.00 per kW (EFCA Brief at 17). EFCA asserts that this $3.08 per kW increase violates the Department's rate design goal of continuity (EFCA Brief at 17). The Company did not specifically comment on the Rate G-3 on-peak volumetric rate or demand rate on brief.

c. Analysis and Findings

According to the Company's allocated COSS, the embedded customer charge for the G-3 Rate class is $218.54 per month (Exhs. NG-PP-1, at 57; NG-PP-2(d), at 22). Based on a review of the bill impacts on customers, the Department finds that the G-3 Rate, designed with an increase in the monthly customer charge from $200.00 to $223.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable.

In the Department's decoupling Order, D.P.U. 07-50-A, we stated that decoupling revenues should be reconciled through the volumetric component of the distribution charge, because that rate design would provide customers with a greater incentive to reduce their energy consumption and would further the goal of promoting demand resources. D.P.U. 07-50-A at 59; see also, D.P.U. 10-70, at 332. Allowing the Company to reduce the volumetric distribution charge to zero in this proceeding is contrary to the Department's findings in D.P.U. 07-50-A and D.P.U. 10-70. A primary rate principle for the Department is to provide customers with the appropriate incentive to consume electricity as efficiently as possible. D.P.U. 10-70, at 332.

Although pricing distribution service on demand use may support the cost-to-serve principle, it is not the best rate structure to promote energy efficiency. D.P.U. 10-70, at 332. Therefore, it would be inappropriate to adopt the Company's proposal to recover all distribution costs through either customer charges, which are fixed, or demand charges, which are more difficult to avoid through energy efficiency. D.P.U. 10-70, at 332.

Another factor in the Department's decision is the current Rate G-3 volumetric distribution time-of-use rate. The Company's current Rate G-3 volumetric rate includes an on-peak volumetric distribution charge, thus providing a price signal to consume energy during off-peak periods (Exh. NG-PP-1, at 55).

Based on these considerations, the Department rejects the Company's proposal to reduce the on-peak volumetric distribution charge for Rate G-3 to zero. The Company is hereby directed to maintain the volumetric distribution charges at their current levels when designing distribution rates in compliance with this Order. Given that the volumetric distribution charges will remain unchanged and the Department allowed the customer charge to increase to $223.00, the remaining increase in distribution rates for Rate G-3 should be applied to the demand charge component of distribution rates, truncated at two decimal places.[320] Therefore, all customers will continue to be charged a volumetric charge for distribution service.

The Department finds that this method for establishing the volumetric charges and demand charges for the G-3 Rate satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the on-peak volumetric charge at $0.00753 per kWh, the off-peak volumetric charge at zero, and the demand charge to collect the remaining class revenue requirement approved in this Order (Exh. NG-PP-3(i) at 4).

8. Street Lighting

a. Introduction

National Grid currently has seven street lighting rates: (1) Rate S-1, for luminaires and supports owned and maintained by the Company; (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 wiring installations with customer-owned foundations and Company-owned and -maintained luminaires and supports; (4) Rate S-3 (Option B), for underground wiring installations with customer-owned luminaires and supports, with limited maintenance by the Company; (5) Rate S-5, for equipment owned and maintained by customers; (6) Rate S-6, for Company-owned decorative street and area lighting, available to municipal and other governmental customers for municipally owned or accepted roadways; and (7) Rate S-20,

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320 The Department disallowed the Company's demand ratchet proposal for Rate G-3 in Section XIII.D.6.a above.

for luminaires and supports owned and maintained by the Company, which is available to any customer on the S-1 rate that agreed to convert all existing incandescent and mercury vapor source lights to sodium-vapor source lights (Exhs. NG-PP-1, at 58-59; NG-JEW-1, at 3-5; DPU-1-1). Rates S-2 and S-3 are closed to new customers (Exh. NG-PP-1, at 58-59).

b. Company Proposals

In its initial filing, the Company proposed to increase the rates for each luminaire and support in Rates S-1, S-2, S-3, and S-6 by 4.41 percent (Exhs. NG-PP-1, at 59; NG-PP-13, at 7-9). The 4.41 percent increase represents the overall street lighting increase necessary to achieve the level of revenue assigned in the revenue allocation process, after calculating the revenue achieved from Rate S-5 (Exh. NG-PP-1, at 59). For the Rate S-5 per kWh rate, the Company divided the cost associated with the support of the distribution system by the total street lighting kWh deliveries (Exhs. NG-PP-1, at 60; NG-PP-15; WP NG-PP-6).

As noted above, National Grid proposes revisions to Rate S-1 for the purpose of offering a Company-owned LED lighting service option to Rate S-1 customers (Exh. NG-JEW-1, at 5). National Grid's proposal allows for customer selection of LED luminaires that are owned and maintained by the Company (Exh. NG-JEW-1, at 5). The Company explained that the LED luminaires would replace existing incandescent, mercury-vapor, and high pressure sodium lighting equipment installed at existing locations, at the customer's request, or could be installed in new locations (Exh. NG-JEW-1, at 5-6).

Under the proposal, when a customer requests the installation of LED lighting equipment, National Grid will require the customer to pay the unamortized balance of the original installation costs, plus cost of removal less salvage value, for the existing streetlights, in excess of one percent of the total streetlights on the customer's account (Exh. NG-JEW-1, at 10-11). The Company proposes to offer four different types of roadway LED fixtures and one post-top LED fixture (Exh. NG-JEW-1, at 6). The proposed LED fixtures range from 30 watts to 275 watts and provide comparable illumination to existing lighting fixtures installed throughout the Company's service area (Exh. NG-JEW-1, at 6). Additionally, National Grid proposes a cap on the number of LED fixtures that it will replace of ten percent per year of the total quantity of active and inactive street and area lighting fixtures per customer account, if that customer is considered a municipal, governmental authority, or public entity (Exh. NG-JEW-1, at 9). Typically, a customer's request to exchange a lighting fixture is incorporated into the Company's work schedules (Exh. NG-JEW-1, at 9). However, National Grid expresses concern with managing operational priorities and ensuring safe and reliable electric service while meeting customer demand for LED fixture installations (Exh. NG-JEW-1, at 9).

Finally, the Company proposed to cancel Rate S-20 and transfer all customers to Rate S-1, effective with the implementation of new rates resulting from this rate case (Exh. NG-PP-1, at 61). Rate S-20 provided customers with an incentive to convert older, less energy efficient technology of incandescent and mercury vapor lamps to more efficient sodium vapor lamps by offering a lower rate to the customer while the Company performed the conversion (Exh. NG-PP-1, at 61). After the Company completes the conversion work, the customer was transferred back to Rate S-1 (Exh. NG-PP-1, at 61). National Grid has converted all of the customers that took advantage of the conversion incentive, though some remain to be transferred to Rate S-1 (Exhs. NG-PP-1, at 61; NG-PP-3(i) at 6; DPU-15-23).

c. Positions of the Parties

DOER argues that the Department should approve the Company's proposed S-1 tariff for the LED lighting option with certain additional revisions (DOER Brief at 2-3). Specifically, DOER contends that the Company should offer its municipal street-lighting customers a 20-watt LED fixture as an economically beneficial replacement for a 50-watt high-pressure sodium ("HPS") fixture (DOER Brief at 3). Further, DOER recommends that the Company offer a 30-watt LED fixture to replace a 70-watt HPS fixture (DOER Brief at 3). DOER claims that these modifications are necessary to encourage municipal customers to convert to the more efficient LED lighting technology (DOER Brief at 3). According to DOER, the Company has agreed to these S-1 tariff revisions (DOER Brief at 3, citing Tr. 6, 808-809; RR-DOER-3).

Additionally, DOER recommends that the Department remove the ten-percent annual cap on LED lighting conversions (DOER Brief at 3). According to DOER, National Grid did not provide any evidentiary support for the ten-percent annual cap or any alternative amount (DOER Brief at 3-4). Therefore, DOER asserts that the ten-percent cap is arbitrary and unsubstantiated (DOER Brief at 4). Instead, DOER recommends that the Company prioritize LED lighting conversions in the context of other customer service priorities, capital investment plans, and storage costs (DOER Brief at 4). Neither National Grid nor any other party commented on the Rate S-1 and S-20 tariff proposals on brief.

d. Analysis and Findings

National Grid has proposed a variety of changes to its street lighting service. The Department has examined the proposed rate design for the street lighting rate classes S-1, S-2, S-3, S-5, and S-6 (Exh. NG-PP-23, at 21-65, and 87-132 (proposed M.D.P.U. Nos. 1270 through

1274 (MECo); and 583 through 587 (Nantucket Electric))). The Department finds that the proposed rate design for the street lighting rate classes satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs National Grid in the compliance filing to compute the street light charges using the method proposed by the Company, subject to our findings on the farm discount, and the increase from the allocation process and revenue requirement for the street light class approved in this Order.

Regarding DOER's recommendations that the Company offer certain LED fixtures to replace existing HPS luminaries, the Company has agreed to accept DOER's recommendation to offer a 20-watt LED fixture that is an economically beneficial replacement for a 50-watt HPS fixture (RR-DOER-3, Att. 2). Further, we note that in its initial filing, the Company already offers a 30-watt LED fixture as a comparable luminaire to the 70-watt HPS (see Exhs. NG-PP-16, at 3; NG-PP-23, at 24 and 90 (proposed M.D.P.U. Nos. 1270, Sheet 4 (MECo); 583, Sheet 4 (Nantucket Electric))).

National Grid corrected its calculations used to determine its proposed LED lighting rates from its initial filing (RR-DPU-21; RR-DOER-3 & Atts). The Department has reviewed National Grid's method of calculating the S-1 rate for the LED lighting option, and finds that it is cost-based and, therefore, reasonable (see RR-DOER-3, Atts.). Therefore, the Department directs the Company in its compliance filing to compute the rate for the LED lighting option for Rate S-1 using the revised method proposed by National Grid, a revised carrying charge calculation pursuant to our findings in Sections VII, VIII.G, and XII, and the allocation process and revenue requirement for the Rate S-5 approved in this Order.

Next, with respect to the Company's proposed cap on fixture replacements, the Company proposed the following provision in its S-1 tariff:

> The Company shall use its best efforts to replace existing lights with LED within a reasonable length of time after receipt of the written notice requesting such replacement. Depending upon the number of street and area lighting facilities to be replaced with LED lights and the availability of the Company's crews, the Company may limit the quantity of LED replacements to 10 [percent] per account per calendar year to allow for efficient operations. The Company reserves the right to be flexible in responding to the Customer's request. However, the Company shall complete all requests according to a mutually accepted schedule between the Customer and the Company upon receipt of written notice.

(Exh. NG-PP-23, at 24, 90 (proposed M.D.P.U. Nos. 1270, Sheet 4 (MECo); and 583, Sheet 4 (Nantucket Electric))).

As noted above, DOER recommends that the Department remove the ten-percent annual cap on LED lighting conversions from the proposed tariff (DOER Brief at 3). The Department agrees with this recommendation. The Company's need to limit replacements at ten percent is speculative and premature (see, e.g., Exhs. DOER-1-3, at 2; DOER-1-7). The Company is unable to provide an estimate regarding the quantity of street lighting fixtures that were replaced for past municipal inquiries into efficient lighting (Exh. DPU-1-2). Additionally, National Grid has previously implemented similar street lighting activities in a way that allowed the Company to work these activities into its existing workload and resource plans (Exh. DOER-1-7). Therefore, the Department directs National Grid to strike the following sentence from its proposed tariff: "Depending upon the number of street and area lighting facilities to be replaced with LED lights and the availability of the Company's crews, the Company may limit the quantity of LED replacements to 10 [percent] per account per calendar year to allow for efficient operations."[321]

Finally, we note that National Grid has converted all customers that took advantage of the Rate S-20 incentive (Exh. NG-PP-1, at 61). Therefore, the Department finds that the Company's proposal to discontinue Rate S-20 is reasonable. Accordingly, the Department approves the cancellation of Rate S-20 and the transfer of all customers who are currently billed on Rate S-20 to Rate S-1.

XIV. PROPOSED FEES AND TARIFF CHANGES

A. Access Fee for Stand-Alone Distributed Generation Facilities

1. Introduction

a. Background

Stand-alone DG facilities are those that are directly connected to the distribution system and have no associated on-site load (Exh. NG-PP-1, at 70). The Company states that because stand-alone DG facilities generally have no on-site load, the facilities are eligible for and typically are assigned to Rate G-1, which is available for any C&I customer who uses less than 10,000 kWh per month (Exh. NG-PP-1, at 73). Customers who take service under the Rate G-1 class, including stand-alone DG facilities, pay a monthly customer charge of $10.00, plus associated taxes (Exh. NG-PP-1, at 73; Tr. 7, at 1124). In addition to the customer charge, all stand-alone DG facilities that apply for interconnection to the Company's distribution system

[321] Should the actual level of replacement of streetlights to LED lights be such that the Company's crews are unable to complete in a timely fashion, then the Company may petition the Department and request an appropriate limit on the pace of replacement. The Department expects that the petition would be supported by sufficient evidence showing that such a limit is warranted.

may incur the costs that are necessary to expand or upgrade the distribution system (i.e., "system modifications") in order for the facility to safely interconnect without adversely affecting the reliability or the distribution system (Exh. NECEC-1-12).[322]

Apart from the customer charge, associated taxes, and any system modification costs, stand-alone DG facilities do not pay any other costs for use of the Company's distribution system (Exhs. NG-PP-1, at 73; NECEC-1-12). In particular, the Company states that interconnection costs for stand-alone DG facilities do not include the costs associated with: (1) the recovery of ongoing O&M and the replacement of interconnection equipment;[323] (2) energy and transmission and distribution ("T&D") service, as well as, non-T&D service for continued use of the electric power system;[324] (3) short term and long term investments to support enhanced quantities of DG on the electric power system;[325] and (4) the interval metering required for the stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3;

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322 See also, Standards for Interconnection of Distributed Generation Tariff, M.D.P.U. No. 1248.

323 The Company identifies the following O&M expenses it incurs to provide service to a stand-alone DG facility: (1) ISO-NE communications and settlement; (2) allocating net metering credits; (3) resolving billing issues; (4) municipal property taxes; (5) repair and replacement of damaged equipment; and (6) vegetation management (Exhs. DPU-21-3, at 2; LI-1-10).

324 The electric power system includes both the distribution system and the transmission system.

325 National Grid states that it has made relatively low-cost investments to date as a result of low levels of DG penetration, but over the long term the Company expects to make higher cost investments to handle two-way power flow between customer DG implementations and the electric distribution system (Exh. EFCA-1-9; Tr. 7, at 1142-1144).

AG-27-8; LI-1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NECEC-1-13; NECEC-1-19).[326]

b. Company Proposal

National Grid proposes to assess new stand-alone DG facilities that take service under its Rate G-1 a monthly access service fee ("Access Fee") (Exh. NG-PP-1, at 70, 73). The proposed Access Fee is intended to recover from the stand-alone DG facilities the costs beyond those recovered from the customer charge, associated taxes, and payments for system modification that are attributable to interconnection with the distribution system (Exhs. NG-PP-1 at 74; AG-27-8). The Company proposes an Access Fee charge of $7.00 per kW-month for customers connected at the primary voltage level and $8.50 per kW-month for customers connected at the secondary voltage level (Exh. DPU-12-4).[327] The Company's proposed Access Fee charges are identical to the proposed demand charges for Rate G-3 (primary voltage fee) and Rate G-2 (secondary voltage fee) (Exh. DPU-12-4).

The Company proposes to calculate the monthly Access Fee by multiplying the applicable Access Fee charge by the nameplate capacity of the stand-alone DG facility, adjusted for its expected availability at peak loading conditions, which the Company refers to as the

[326] To comply with ISO-NE load reporting requirements, National Grid must install for these stand-alone DG facilities a complex and expensive interval meter that typically is installed on larger C&I customers. The cost of this type of meter is not included in the Rate G-1 revenue requirement (Exh. NG-PP-1 at 74). The Company provides a cost estimate of $1,690 to install an interval meter for a stand-alone DG facility (Exh. NECEC-1-19 & Att.).

[327] Under the Company's proposed Access Fee charge, voltage greater than or equal to 1,000 volts would qualify as a primary voltage; voltage less than 1,000 volts would qualify as secondary voltage (Exhs. NG-PP-1, at 71; DPU-12-4).

"capacity availability factor" (Exhs. NG-PP-1, at 70-72; DPU-12-4).[328,329] National Grid proposes that the Access Fee will apply to stand-alone DG facilities applying for interconnection service after the effective date of its proposed Phase I rates, however, the Company will not begin billing the proposed Access Fee until its proposed Phase II rates go in effect, which is expected to be no earlier than April 2017 (Exhs. NG-PP-1, at 72-73; NG-PP-Rebuttal-1, at 48; DPU-12-5) (see Section XIII.D.3 above). Finally, the Company proposes that all revenues it bills for the Access Fee will be credited to customers through the RDM (Exh. DPU-32-30).

c. Chapter 164, § 139(j)

On April 11, 2016, Governor Baker signed into law Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy ("Solar Act"). Among other things, the Solar Act amended General Laws Chapter 164 by adding Section 139(j) ("§ 139(j)"), which provides:

> (j) Distribution companies may submit to the department proposals for a monthly minimum reliability contribution to be included on electric bills for distribution utility accounts that receive Class I, Class II, Class III, or market net metering credits pursuant to this section, subject to the review and approval of the department. Any such minimum contributions shall ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system. Proposals shall be filed with the department in: (i) the distribution company's base distribution rate proceeding; or (ii) a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes. The department may

328 The Company defines the capacity availability factor as the peak load in kilowatts that a turbine or solar array needs from the distribution system to monetize its output (Tr. 7, at 1170).

329 The Company proposes the following capacity availability factors for stand-alone DG facilities: solar- 40 percent; wind – 30 percent; anaerobic digestion – 50 percent; and hydroelectric – 10 percent (Exhs. NG-PP-1 at 72, DPU-12-4). Thus, for example, a monthly access fee for a 1-MW stand-alone DG facility connected at the primary voltage level would incur a $2800 monthly access fee. The calculation would be $7.00 Access Fee charge x 1000-kW nameplate capacity x 40 percent solar capacity availability factor (Exh. DPU-12-4).

> approve a monthly minimum reliability contribution that: (i) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (ii) does not excessively burden ratepayers; (iii) does not unreasonably inhibit the development of Class I, Class II, Class III facilities; and (iv) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance and safety of the electric distribution system.
>
> 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 commonwealth is equal to or greater than 1,600 megawatts. The department shall conduct a full adjudicatory proceeding when reviewing proposals for a monthly minimum reliability contribution, which shall include at least [one] public hearing and an opportunity for public comment.

See also 220 C.M.R. § 18.10.

National Grid submits that the proposed Access Fee meets the purpose of § 139(j), as it is intended as a monthly contribution from stand-alone DG customers to ensure that these customers contribute toward the fixed costs of ensuring the reliability, proper maintenance, and safety of the electric distribution system (Exh. NG-PP-Rebuttal-1, at 47). Further, the Company submits that while § 139(j) provides for a monthly minimum reliability contribution ("MMRC"), it does not expressly curtail or prohibit the Department, acting pursuant to its plenary ratemaking authority, from approving the proposed Access Fee in another manner (such as on an earlier timeframe) (Exh. NG-PP-Rebuttal-1, at 47). Moreover, National Grid contends that assuming the requirements of the statute are applicable to its proposed Access Fee, these requirements have been satisfied because its proposed Access Fee: (1) equitably allocates fixed costs not caused by volumetric consumption; (2) does not excessively burden its customers; (3) will not unreasonably inhibit the development of DG facilities; and (4) is dedicated to offsetting the Company's reasonable and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the distribution system (Exh. NG-PP-Rebuttal-1, at 47). Finally, the

Company notes that the implementation of its proposed Access Fee is expected to coincide with the expected date that the aggregate nameplate capacity of installed solar generating facilities in the Commonwealth is equal to or greater than 1,600 megawatts, as described in § 139(j) (Exh. NG-PP-Rebuttal-1, at 47).

2. Positions of the Parties

a. Intervenors, Limited Intervenors, and Limited Participants

i. Introduction

Eversource supports the Company's proposed Access Fee. According to Eversource, the proposed Access Fee is appropriate because: (1) the record in this case demonstrates that stand-alone DG facilities impose costs on the distribution system similar to the costs imposed by medium- and high-use commercial customers yet these stand-alone DG facilities pay the same customer charge as low-use commercial customers; (2) the Company does not recover the full costs to serve stand-alone DG facilities; and (3) the Company's other customers cross-subsidize the stand-alone DG customers (Eversource Brief at 2-3). Further, Eversource asserts that the Department has the ratemaking authority to approve the proposed Access Fee, which Eversource contends complies with the MMRC provision of the Solar Act (Eversource Brief at 2-3).

On the other hand, the Acadia Center, EFCA, NECEC, and Vote Solar (collectively as "Limited Intervenors"), along with the Attorney General, DOER, and PowerOptions, all oppose the Company's proposed Access Fee. Their arguments essentially are three-fold: (1) there is insufficient evidentiary support for the proposed Access Fee; (2) the proposed Access Fee is not a valid substitute for the MMRC; and (3) the proposed Access Fee is inconsistent with the Department's rate design goals. These arguments are discussed in further detail below.

ii. Evidentiary Support for the Proposed Access Fee

Several commenters argue that the Company bears the burden of proving the propriety of any of its proposed rate increases, including documenting and quantifying with record evidence the distribution costs it claims that stand-alone DG customers are shifting to other customers (Acadia Center Reply Brief at 3; DOER Reply Brief at 5; EFCA Reply Brief at 3). In this regard, the Limited Intervenors and the Attorney General contend that the Company did not provide record evidence to show that the Access Fee is required to recover costs that the stand-alone DG facilities impose on the distribution system, or that the Access Fee is set at an appropriate level, or that, absent an Access Fee, there would be a cost shift from stand-alone DG customers to non-DG customers (Attorney General Brief at 145-146; Acadia Center Brief at 15-16; EFCA Brief at 9-10; NECEC Brief at 37; Vote Solar Brief at 20; Vote Solar Reply Brief at 10).

In particular, the Attorney General contends that National Grid does not provide sufficient information for the Department to properly design or evaluate the proposed Access Fee, as the Company fails to include any analysis of (1) current costs for stand-alone DG facilities' use of the distribution system, or (2) incremental distribution system costs for upgrades to accommodate additional stand-alone DG facilities (Attorney General Brief at 145-146). Further, Acadia Center argues that the Company has not shown that the current rate design is unfair where stand-alone DG customers pay their marginal cost and non-DG pay reliability costs, safety costs, and other embedded costs (Acadia Center Brief at 15-16). EFCA also asserts that the Company provided no evidence that DG customers are shifting costs to non-DG customers (EFCA Brief at 9-10). Further, NECEC argues that National Grid provided no analysis to show the actual cost to serve stand-alone DG facilities, but rather the Company merely asserts that such costs exist because of the expanded adoption of DG resources (NECEC Brief at 37). Finally, Vote Solar maintains that as the Company does not quantify the costs that stand-alone DG customers impose on the distribution system, consequently the Company does not know if these customers contribute more or less revenue than is the cost to serve (Vote Solar Brief at 20; Vote Solar Reply Brief at 10).

Next, DOER and several of the Limited Intervenors argue that the Company provided no evidence to prove that stand-alone DG facilities impose the same costs on the distribution system as are imposed by a Rate G-3 or Rate G-2 customer (DOER Brief at 9-10; EFCA Brief at 22-25; EFCA Reply Brief at 17-18, 21; NECEC Brief at 33-36; NECEC Reply Brief at 2; Vote Solar Brief at 21; Vote Solar Reply Brief at 10). DOER and the Limited Intervenors also contend that the Company's rationale, that the Access Fee is appropriate because the distribution system must be sized to accommodate maximum demand whether inflow or outflow of electricity, is flawed because: (1) diversity of demand ensures that any individual customer's use of the distribution system is not a significant driver for sizing upstream portions of the system; (2) stand-alone DG resources pay for necessary system upgrades in their vicinity through the interconnection process; (3) backflow,[330] from the two-way power flows, is not a significant problem for the

[330] The Company notes that backflow (or "backfeed") occurs on the distribution system when power on a radial distribution system that is designed to flow from substations out to customers flows back into the substation from DG located on the feeder (Tr. 7, at 1007).

Company's distribution system;[331] and (4) electricity produced by stand-alone DG facilities during peak demand time reduces demand on the upstream portion of the distribution system (DOER Brief at 9-10; Acadia Center Brief at 15-16; EFCA Brief at 11, 22-25; EFCA Reply Brief at 17-18, 21; NECEC Brief at 33-36; NECEC Reply Brief at 2; Vote Solar Brief at 21; Vote Solar Reply Brief at 10).

In addition, the Attorney General and EFCA argue that the Company failed to justify certain cost categories that it uses to substantiate the need for its proposed Access Fee (Attorney General Brief at 146; EFCA Reply Brief at 5). In particular, the Attorney General asserts that the Company failed to justify such costs as on-going customer service aspects and the need for further investments to its distribution system (Attorney General Brief at 146). EFCA posits that the Company only quantifies costs for two additional full-time employees and future O&M expenses as costs that it presently does not recover in stand-alone DG customers' interconnection fees (Exh. LI 1-21; EFCA Brief at 9, n.27; EFCA Reply Brief at 5; Tr. 7, at 1067, 1070-71).

The Attorney General, DOER and NECEC also raise issues regarding the sufficiency of the evidence regarding the capacity availability factors. According to the Attorney General and NECEC, the Company's capacity availability factors are flawed, violate the principles of cost causation, and lacks transparency (Attorney General Brief at 142-145; NECEC Reply Brief at 7-8). In this regard, the Attorney General and NECEC maintain that the Access Fee calculation does not recognize the load reducing benefits of DG, which reduce the Company's distribution system costs when the stand-alone DG facilities generate power during peak hours;

331 The Attorney General maintains that a number of the Company's feeders are experiencing back flow conditions (Attorney General Brief at 145 n.51, citing Exhs. AG- 27-14, Att.; NECEC-1-16, Att. (Supp.); RR-AG-24).

rather, they contend that the Company designed the Access Fee calculation to increase if the load reducing benefits increase from a higher capacity availability factor (Attorney General Brief at 142-143; NECEC Reply Brief at 8).[332] According to the Attorney General, an Access Fee proposal aligned with cost-causation should increase where the cost-reducing benefits of a stand-alone DG facility decreases (Attorney General Brief at 142-143). In addition, the Attorney General contends that using a system-wide availability factor to calculate the Access Fee does not accurately track cost causation for all DG technology types, because peak times vary by the customer mix on a given feeder (Attorney General Brief at 144). Further, the Attorney General claims that the Company did not provide adequate support for using a 40-percent solar capacity availability for the Access Fee calculation (Attorney General Brief at 144-145). Finally, DOER argues that the Company improperly used a limited sample size of wind, anaerobic digestion, and hydroelectric facilities to determine the proposed capacity availability factors (DOER Brief at 10).

The Attorney General and several Limited Intervenors also argue that in, addition to the lack of evidence to support the costs and design of the proposed Access Fee, National Grid failed to provide complete data on the benefits and costs associated with DG in general, and, without this information, the Company cannot fully understand the impact of increasing DG penetration on its distribution system and determine whether DG customers will be charged the appropriate

[332] The Attorney General contends that the Access Fee as proposed would increase if a stand-alone DG facility provides more generation into the Company's distribution system (Access Fee = voltage charge x nameplate capacity x capacity availability factor) (Attorney General Brief at 142-143, citing Tr. 7, at 1148-1153). The Attorney General explains that this result is counterintuitive. If generation from these stand-alone DG facilities increases during periods when the Company experiences peak load condition, the stand-alone DG facilities will decrease the system peak and, therefore, decrease the Company's overall system costs (Attorney General Brief at 142-143).

cost of service (i.e., Access Fee) (Attorney General Brief at 145-146; Acadia Center Brief at 10-12; EFCA Brief at 11; EFCA Reply Brief at 4-5, 6-7, 20; NECEC Brief at 46). According to the Attorney General and these Limited Intervenors, further study of costs and benefits is necessary to fairly assess and assign incremental costs that DG customers impose on the distribution system (Attorney General Brief at 145-147; Acadia Center Brief at 10-12; EFCA Brief at 10-11; EFCA Reply Brief at 6-7, 20; NECEC Brief at 46). Further, Acadia Center and EFCA note that National Grid is participating in regulatory proceedings in New York,[333] and Rhode Island,[334] that seek to identify and quantify the benefits and costs of DG, so it is reasonable to expect that the Company would do the same in the instant proceeding as part of its Access Fee proposal (Acadia Reply Brief at 3-4; EFCA Reply Brief at 6-7). Moreover, Acadia Center contends that the value of DG resources should be a part of the next evolutionary phase in economic analysis of ratemaking as it is a key element in analysis of cost shifts (Acadia Center Brief at 10-11). Further, the Attorney General argues that a properly designed access fee, including costs and benefits, would take into account any incremental distribution system costs

[333] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources at the New York Public Service Commission (Acadia Center Reply Brief at 3, n.9). EFCA and Acadia Center remark that National Grid is a signatory to the New York Progress Partnership, a New York REV (Revolutionizing the Energy Vision) regulatory proceeding that seeks to value DG and distributed energy resources in which utilities conduct a benefit-cost analysis to quantify the value and explore how to incent DG facilities to cite facilities in locations that will maximize their benefit to the grid (Acadia Center Reply Brief at 3-4; EFCA Reply Brief at 7, citing Exh. EFCA-CG-Rebuttal-1, at 12).

[334] Docket 4600, Investigation into the Changing Distribution System and the Modernization of Rates in Light of the Changing Distribution System, at the Rhode Island Public Utilities Commission (Acadia Center Reply Brief at 3 n.9).

driven by upgrades needed to accommodate DG, which depends on whether the location of the DG is reducing or adding feeder load (Attorney General Brief at 145).

Several of the Limited Intervenors reject the Company's claim that there is little evidence of locational capacity benefits from DG on its system; they argue that the record includes evidence that demonstrates locational benefits (Acadia Center Reply Brief at 10; EFCA Reply Brief at 6-7; NECEC Brief at 39-41). For instance, NECEC argues that stand-alone DG facilities on the Company's distribution system reduced maximum circuit loads by ten percent on those circuits serving such stand-alone DG facilities, which then provided additional capacity to serve other customers; and in Massachusetts, an average distributed generation resource provides 36 percent of its nameplate capacity during times of peak feeder loading (NECEC Brief at 40-41). EFCA maintains that the Company recognized the load relief provided by DG projects by incorporating solar capacity on its system into its load forecasting, and that the Company conceded that the output from a stand-alone DG customer reduces the upstream load on the distribution system (EFCA Reply Brief at 20; EFCA Brief at 11; Tr. 5, at 737). Further, EFCA rejects the Company's claim that it is double-counting to quantify distribution system benefits both from solar in solar renewable energy credits ("SRECs")[335] and from net metering incentives (EFCA Reply Brief at 8). EFCA asserts that the Company's argument that SRECs are a proxy for the total value that distributed resources provide to the grid is erroneous as distributed

335 According to EFCA, SRECs value is based primarily on the targets that "state policy-makers" assign to supply and demand as a means of incenting carbon reductions, which is independent of the total value of distributed generation on the Company's distribution system (EFCA Reply Brief at 8). Further, EFCA contends that SRECs are environmental commodities that represent the environmental attributes from renewable energy resources and should be taken into account (EFCA Reply Brief at 8).

resources provide more than environmental benefits, and that the Company does not present any evidence of the value of SRECs (EFCA Reply Brief at 8).

iii. MMRC and the Solar Act

The Attorney General and NECEC argue that, as a threshold procedural matter, the Department cannot approve the Company's proposed Access Fee as a MMRC because Massachusetts has not yet reached the 1,600-megawatt aggregate nameplate capacity of installed solar generating facilities, and will likely not reach this threshold until 2017 (Attorney General Brief at 140-141; NECEC Brief at 49, citing § 139(j)).

NECEC and Vote Solar contend that National Grid's proposed Access Fee does not meet the requirements of § 139(j) because the Company has failed to demonstrate that the proposed Access Fee: (1) equitably allocates the fixed costs of the electric distribution system, as the Company has not conducted any analysis to equate the demand-related costs to serve Rate G-2 and Rate G-3 customers to that of stand-alone DG facilities; (2) will not excessively burden ratepayers as it does not quantify costs attributed to stand-alone DG facilities; (3) will not unreasonably inhibit the development of Class I, Class II and Class III net metering facilities;[336] and (4) will offset reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the distribution system (NECEC Brief at 48-51; Vote Solar Brief at 23-25; Vote Solar Reply Brief at 13-18).

Acadia Center also argues that the proposed Access Fee contradicts the stated policy goals of the Solar Act, which Acadia Center claims are to support community-shared and low income solar facilities, and that the proposal may encourage more expensive on-site solar

[336] The three classes of net metering facilities are defined in 220 C.M.R. § 18.02.

projects rather than more cost-effective stand-alone DG facilities (Acadia Center Brief at 16, citing, Exh. AC-AA-Rebuttal-1, at 7; Acadia Center Reply Brief at 10). Further, Acadia Center, EFCA, and Vote Solar contend that the Department should reject the Company's proposed Access Fee as unnecessary because the Solar Act provides for a 40-percent reduction in the market net metering credits to alleviate any purported cost shifts from DG customers to non-DG customers (Acadia Center Brief at 17; EFCA Reply Brief at 5-6; Vote Solar Brief at 25). Further, EFCA questions whether the Access Fee is legal under the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[337] as EFCA alleges that the Company's proposal constitutes a fee on qualifying facilities that could make the cost to operate a qualifying facility economically prohibitive (EFCA Brief at 26).

The Attorney General and PowerOptions recommend that the Department open a generic proceeding to consider creating a standardized MMRC or Access Fee applicable to stand-alone DG facilities, so that all potential stakeholder can participate in the process (Attorney General Brief at 147-148; PowerOptions Reply Brief at 8-9). According to the Attorney General and PowerOptions, a general proceeding would allow the Department to decide many of the issues relevant to the design of an Access Fee before the 1600-MW threshold is met and to promote administrative efficiency for future base rate proceedings (Attorney General Brief at 147-148; PowerOptions Reply Brief at 8-9).

[337] PURPA, Pub. L. 95–617, 92 Stat. 3117 was passed as part of the National Energy Act of 1978. EFCA notes that PURPA is meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply) (EFCA Brief at 26 n.87).

iv. Rate Design Issues

NECEC notes that it supports re-evaluating rate design so that rates send accurate price signals that allow customers to optimize energy consumption and encourage the deployment of advanced technologies (NECEC Reply Brief at 2-3). Acadia Center also supports reforms to rate design that correct for significant cost shifts, such as the MMRC (Acadia Center Reply Brief at 4-5). However, NECEC and Acadia Center, along with DOER, argue that the Company's proposed Access Fee would not meet the Department's rate design goals of fairness and efficiency (DOER Brief at 10; Acadia Center Brief at 10; NECEC Brief at 39). In particular, DOER contends that the Access Fee is inconsistent with the Department's rate design goal of fairness as the Company's proposal targets only those DG facilities that export all power to the grid and not those that consume some power on-site (DOER Brief at 10).

Further, NECEC maintains that National Grid's Access Fee is contrary to the Department's rate design goal of sending efficient price signals because the Company failed to appropriately allocate any costs associated with stand-alone DG facilities in a fair and equitable manner as required under G.L. c. 164, § 142, and it did not consider various benefits of DG[338] (NECEC Brief at 39). Additionally, NECEC joins Vote Solar in arguing that the Department must reject the Company's proposed Access Fee because the Company failed to consider the impacts of its rate design proposal on the successful development of energy efficiency and DG, as required under G.L. c. 164, §§ 141, 142 (NECEC Brief at 39, 42; NECEC Reply Brief at 13; Vote Solar Brief at 22-23; Vote Solar Reply Brief at 12-13).

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338 As an example of a benefit that DG provides to the grid, NECEC cites avoided line losses from using generation located near load rather than transporting generation from a more distant source (NECEC Brief at 39-40).

b. National Grid

i. Evidentiary Support for the Proposed Access Fee

The Company argues that it is experiencing a growing cost shift from net metering customers to non-net metering customers from increased net metering incentives,[339] and that the bulk of distribution service costs are recovered through the variable portion of distribution rates,[340] instead of through fixed rates (Company Brief at 213-215). Further, the Company contends that the price for distribution service should be based on transparent and efficient rate designs that reflect the costs to provide service to both DG and non-DG customers (Company Brief at 212-213). As such, the Company proposes the Access Fee to reflect the costs imposed on the distribution system by the stand-alone DG facilities (Company Brief at 212-214, 228).

The Company argues that it proposed to set the Access fee at the same values as the demand charges proposed for Rates G-2 and G-3 customers because stand-alone DG customers use the distribution system for exporting electricity in the same way that customers on Rates G-2 and G-3 use the distribution system to import electricity (Company Brief at 229 citing Exhs. DPU-12-4, AG-27-10; Company Reply Brief at 95-96). More specifically, the Company contends that whether a particular customer imports or exports electricity, that customer relies on the electric distribution system and the services provided by the Company, and imposes a demand on the distribution system for which the system must be designed to

[339] The Company calculates that the net costs to customers from net metering amounts to $27.99 million in 2014 and $53.14 million in 2015 (Exh. EFCA 1-3, Att. 1-3-2).

[340] In addition to net metering credits, the Company contends that the cost shift consists of (1) O&M costs; (2) energy, transmission and distribution costs and (3) short- and long-term investments to support DG (Exhs. EFCA 1-3; EFCA 1-9; EFCA 1-11; EFCA 2-7; LI 1-10; AG-27-8).

accommodate (Company Brief at 229, citing, Exhs. NG-PP-Rebuttal-1, at 33; AG-27-10; Company Reply Brief at 95). Thus, the Company asserts that the proposed Access Fee has been appropriately set at the same values as the demand charges proposed for customers in Rate G-2 and Rate G-3, respectively (Company Brief at 229, citing Exh. DPU-12-4; Company Reply Brief at 95-96).

The Company argues that while Department precedent requires companies to design rates based on cost causation as well as balancing a number of oft-competing policy goals, there are practical limitations in establishing the level of the cost to serve and recovering those costs from customers (Company Brief at 211-212).[341] The Company contends that many of the criticisms of its rate proposals would require the Company to undertake an unprecedented level of precision in determining cost-causation; such an undertaking is not practical or required for ratemaking purposes (Company Brief at 212).

Further, National Grid rejects any notion that is has not met its burden of proof relative to the proposed Access Fee because it has not conducted special cost studies to demonstrate that the costs incurred to flow electricity in one direction are the same as the costs to flow the electricity in the other direction (Company Brief at 230, citing, DOER Brief at 9-10; EFCA Brief at 23; NECEC Brief at 37-38; Company Reply Brief at 96). The Company claims that such an analysis may not be possible, and even if it were, it would be meaningless because the distribution system still has to be constructed to meet demand, regardless of which way electricity flows (Company

[341] For example, the Company notes that costs are generally not calculated for individual customers, but rather for groups of homogenous customers with similar cost-causation attributes; and Department goals of simplicity, continuity, and earnings stability may temper the implementation of cost-based rates (Company Brief at 212, Exh. NG-PP-1, at 39-41).

Brief at 230, citing Exh. AG-27-10; Company Reply Brief at 96-97). Further, the Company asserts that the Intervenors and Limited Intervenors have provided no basis for the claim that the costs incurred to transport power away from a stand-alone DG facility is different from the costs incurred to transport power to a similarly sized retail customer (Company Brief at 231, citing Tr. 12, at 1330-1336; Company Reply Brief at 97).

The Company also dismisses any claims that the proposed Access Fee fails to account for any benefits of stand-alone DG facilities associated with their contribution toward distribution capacity (Company Brief at 231, citing, Attorney General Brief at 142-143; DOER Brief at 9-10; EFCA Brief at 23-25; NECEC Brief at 39-41; Company Reply Brief at 97). The Company contends that the record shows that stand-alone DG projects have been constructed in areas remote from load and that the generation from these facilities does not typically match feeder, substation, or system peak loads (Company Brief at 231, citing Exh. NG-PP-Rebuttal-1, at 37; Company Reply Brief at 97). Therefore, according to the Company, the claimed distribution capacity benefits of stand-alone DG facilities are “illusory” (Company Brief at 231; Company Reply Brief at 97). Further, National Grid argues that the record shows that the Company does consider solar capacity in its load forecasting methodology, as well as using actual measured peak loads on feeders and at substations (Company Brief at 231; Company Reply Brief at 97). Thus, the Company asserts that any load relief benefits created by solar will be realized over time in a similar fashion as the load relief provided by over 30 years of energy efficiency programs and services (Company Brief at 231; Company Reply Brief at 97).

With respect to system benefits from DG, the Company maintains that: (1) while correctly located DG may provide benefits, it has little hard evidence of such benefits within its service territory;[342] and (2) system benefits of solar DG already have been assumed by the Commonwealth through implementation of net metering and the solar carve-out incentives (Company Brief at 215-216; Exh. NG-PP-Rebuttal-1, at 37). The Company alleges that, in light of these solar DG incentives, counting distribution system benefits from solar DG as an offset to distribution system costs would constitute double-counting, creating bill impacts to all customers (Company Brief at 216). The Company asserts that performing a cost-benefit or value-of-solar study to establish rates, as suggested by the Limited Intervenors, would be a departure from the Department's traditional ratemaking framework that raises more questions than it answers (Company Brief at 216).

ii. MMRC and Solar Act

On brief, the Company repeats its positions set forth in rebuttal testimony regarding the propriety of the proposed Access Fee in the context of § 139(j) and the MMRC (Company Brief at 231-233; Company Reply Brief at 97-99; see Section XIV.A.1.c above). In particular, the Company argues that: (1) the Department has the authority to approve the Access Fee irrespective of § 139(j); (2) assuming that the requirements of the statute apply to the proposed Access Fee, the requirements have been satisfied; and (3) by the time the proposed Access Fee is imposed, the 1600-megawatt threshold will likely be achieved (Company Brief at 231-233; Company Reply Brief at 97-99).

[342] The Company contends that any distribution benefits from stand-alone DG facilities are illusory as record evidence shows that stand-alone DG projects have been constructed in remote areas away from load and do not match feeder, substation or system peak loads; any load relief benefits created by solar will only be realized over time similar to energy efficiency programs (Exh. NG-PP-Rebuttal-1, at 37; Company Brief at 231; Company Reply Brief at 97).

iii. Rate Design Issues

The Company does not specifically address the arguments of the Intervenors and Limited Intervenors regarding whether the proposed Access Fee meets the Department's rate design goals. However, the Company argues that its rate design proposals, which include the proposed Access Fee, meet the Department's rate design goals, represent a substantial improvement over its current rate design, and are the first step in a process towards an optimal rate design, which would include both customer and demand charges for each rate class (Company Brief at 213-214).

3. Analysis and Findings

National Grid argues that its proposed Access Fee is necessary to recover costs imposed on the distribution system by stand-alone DG facilities that take service under Rate G-1, but use the distribution system in the same manner as a typical Rate G-2 or Rate G-3 customer does (Exhs. NG-PP-1, at 74; AG-27-8; Tr. 5, at 653). According to National Grid, stand-alone DG facilities do not pay for O&M and some capital costs that they impose on the Company's distribution system (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3; AG-27-8; LI 1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NeCEC-1-13; NECEC-1-19). National Grid claims that stand-alone DG facilities' lack of contribution creates a growing cost shift, as the Company is required to socialize these costs by recovering them from all distribution customers (Company Brief at 212-214, 228-229).

As noted above, the Company claims that interconnection costs for stand-alone DG facilities do not include the costs associated with: (1) the recovery of ongoing O&M and the replacement of interconnection equipment; (2) T&D and non-T&D service for continued use of the electric power system; (3) short term and long term investments to support enhanced quantities of DG on the electric power system; and (4) the interval metering required for the stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3; AG-27-8; LI-1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NECEC-1-13; NECEC-1-19). The record shows, however, that with the exception of interval meters, the Company has not quantified the costs that it contends stand-alone DG facilities impose on its distribution system (Exhs. EFCA 1-9, at 2; EFCA-1-10, at 2; NECEC 1-13, NECEC 1-19; Tr. 5, at 647-654). For instance, the Company identifies several categories of O&M associated with system modifications to stand-alone DG facilities to estimate O&M costs, but it does not quantify the actual O&M costs incurred by operating stand-alone DG facilities (Exhs. DPU-29-8; LI-1-10, EFCA-1-9, at 2, EFCA-1-11, EFCA-2-7, NECEC-1-13, DPU-21-3, Tr. 5, at 646, 652-654). Further, National Grid has not specifically quantified T&D and non-T&D costs related to use of the Company's system by stand-alone DG facilities (Tr. 5, at 649-651). In addition, the Company identifies, but does not quantify, other short- and long-term capital investments it states will need to be made to accommodate higher penetration of stand-alone DG facilities on its distribution system (Exhs. LI 1-10, LI 1-22, EFCA 1-9, EFCA 1-11). Rather, apart from the interval meters, the Company seems to rely on the allocated COSS applicable to the Rate G-2 and Rate G-3 classes as the cost basis for the proposed Access Fee (Tr. 5, at 644-645, 646, 648, 650-651).

Based on these considerations, we find that the amount of costs that the Company seeks to recover through the proposed Access Fee is not based on sufficient quantification of all of the costs that stand-alone DG facilities impose, but rather rests primarily on demand-related costs of

Rate G-2 and Rate G-3 customers, as determined by the allocated COSS (Exhs. DPU-12-4; DPU-29-9; AG-27-10; Tr. 5, at 652-653; Tr. 7, at 1122-1123). Further, the Company has not conducted an appropriate analysis to determine whether the reliance on the distribution system by a typical stand-alone DG facility is greater than, equal to, or less than customers on Rate G-2 and Rate G-3 (Exh. AG-27-10; Tr. 5, at 654). Therefore, we are not persuaded that the Company's reliance on costs attributable to Rate G-2 and Rate G-3 customers provides a sufficiently reliable cost basis to derive an Access Fee attributable to stand-alone DG customers who take service on Rate G-1. Accordingly, we decline to accept the Company's proposal.

The Department notes that our decision today should not be construed as a rejection of the concept of an Access Fee for stand-alone DG facilities.[343] The Department recognizes that there are distribution system-related costs that may be associated with these facilities for which the stand-alone DG customer should be responsible.[344] However, without a sufficiently reliable quantification of those costs, we are unable to approve the proposed Access Fee. Having rejected the Company's proposed Access Fee, we need not address the other arguments raised by the Intervenors, Limited Intervenors, and Limited Participants.

Further, we decline in this case to consider the Company's proposed Access Fee in the context of a MMRC under the Solar Act. The provision of the Solar Act permitting a MMRC

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[343] The Company also considered as an alternative proposal to assign stand-alone DG facilities to retail delivery service tariffs commensurate with the size of the DG unit, such as Rate G-2 or Rate G3 (Exh. NG-PP-1, at 75). The Department is not necessarily opposed to such a concept, but notes that such a proposal would need to be supported by sufficient evidence showing that the costs attributable to the stand-alone DG facility are commensurate with costs caused by Rate G-2 or Rate G-3 customers.

[344] The Department also recognizes that there are distribution system related revenues that are associated with net metering (RR-DPU-26).

proposal was enacted after the filing of this base rate case, and it contains specific procedural requirements that have not been satisfied here.[345] The Department currently is evaluating the timeline and implementation of potential MMRC proposals. Net Metering Rulemaking, D.P.U. 16-64-D at 16-17 (2016). Therefore, at the appropriate time, the Company may submit a proposal for a MMRC pursuant to § 139(j).[346]

Finally, we find that National Grid has provided sufficient quantification of the $1,690 cost of the interval meters required for stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; NECEC-1-19 & Att.). Therefore, we allow the Company to recover this cost from new stand-alone DG facilities who take service under Rate G-1. The Company shall revise its Standards of Interconnection of Distributed Generation tariff accordingly.

B. Application Fee for Simplified Distributed Generation Applications

1. Introduction

The Company's Standards for Interconnection of Distributed Generation tariff ("Interconnection Tariff") (M.D.P.U. No. 1248) includes a fee structure applicable to interconnecting DG customers that varies depending on the size and type of interconnection. The fee structure was originally approved by the Department in 2004 and more recently reviewed and approved in 2013 following a DG working group process, which included the electric distribution companies and many stakeholders. See Distributed Generation

345 In particular, we note that the Company first addressed the MMRC provision in its rebuttal testimony, after discovery closed, and approximately two weeks before evidentiary hearings began. There was no public hearing relative to a MMRC, or opportunity to comment from interested parties.

346 This statute requires a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes.

Interconnection, D.P.U. 11-75-E at 36, 40 (2013); Investigation Into Distributed Generation, D.T.E. 02-38-B at 41 (2004).

The Company's current Interconnection Tariff exempts interconnection fees for a generating facility using the "Simplified Process" of interconnecting to the Company's electric distribution system (Exhs. NG-RRP-1, at 18; EFCA-1-6, at 2; M.D.P.U. No. 1248, § 3.10 (Table 6)).[347] However, the current tariff includes a $4.50 per kW interconnection fee for customers that choose either the Expedited Process,[348] or the Standard Process,[349] of interconnecting (M.D.P.U. No. 1248, § 3.10 (Table 6)).

2. Company Proposal

The Company proposes to assess a $28.00 one-time application fee for interconnecting DG customers that use the Simplified Process (Exhs. NG-MLR-1, at 21; NG-RRP-1, at 18;

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[347] The Simplified Process is applicable to interconnecting customers (i) using certain single-phase inverter-based facilities with power ratings of 15 kilowatt or less at locations receiving single-phase, secondary service from a single-phase transformer, or (ii) using certain three-phase inverter-based facilities with power ratings of 25 kilowatt or less at locations receiving three-phase, secondary service from a three-phase transformer configuration, and requesting an interconnection on a radial electric system where the aggregate generating facility capacity is less than 15 percent of feeder/circuit annual peak load and, if available, line segment (M.D.P.U. No. 1248, § 3.1). This process is the fastest and least costly interconnection path (M.D.P.U. No. 1248, § 3.1).

[348] The Expedited Process is open to certain larger interconnecting customers that do not qualify for the Simplified Process or the Standard Process (M.D.P.U. No. 1248, §§ 3.3, 3.10 (Table 6)).

[349] The Standard Process is open to any size interconnecting customer, but it has the longest maximum application time period and highest potential costs (M.D.P.U. No. 1248, §§ 3.4, 3.10 (Table 6)).

NG-PP-24, at 286 (proposed M.D.P.U. No. 1285 (Table 6)); Tr. 7, at 1160).[350] The Company states the application fee is intended to cover costs associated with the intake and processing of the Simplified Process applications, such as: (1) reviewing applications for accuracy and completeness; (2) performing a technical screening based on the proposed equipment and characteristics of the local electric power system; (3) answering questions about the interconnection process; (4) providing the customer with status updates by email and/or phone; (5) reviewing completion documentation; (6) authorizing interconnection; and (7) validating processing timelines with customers in anticipation of annual reports to the Department (Exh. DPU-29-12; Tr. 7, at 1161-1162).

National Grid states that the primary reason for the proposed application fee is the significant growth in the number of Simplified Process applications on radial circuits received by the Company in recent years, and the associated cost of processing those applications (Exhs. NG-RRP-1, at 18-19; EFCA-1-6, at 2; Tr. 7, at 1163). In particular, National Grid notes that during the test year, the Company processed 13,027 Simplified Process applications, which was an increase of 8,821 applications (or 210 percent) from the previous year (Exh. NG-RRP-1, at 18-19).[351]

The Company derived the $28.00 application fee by considering the current application fee of $4.50 per kW applicable to interconnecting customers applying for interconnection through the Expedited or Standard Process. More specifically, the Company first determined

350 The Company does not propose any changes to the Expedited or Standard Process fees (<u>see</u> Exh. NG-PP-24, at 286 (proposed M.D.P.U. No. 1285 (Table 6)).

351 The Company states that from approximately 2004 to 2006, the Company received only 64 Simplified Process applications (Exh. EFCA-1-6, at 2).

that the total capacity in kW of the interconnecting customers that applied through the Simplified Process during the test year was 81,636 kW (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13). The Company then multiplied this total by the $4.50 per-kW application fee applicable to Expedited and Standard Process applications to arrive at $367,362 (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13). Next, the Company divided this total by the number of Simplified Process applications received during the test year of 13,027 and rounded to the nearest dollar to arrive at $28.00 (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13; Tr. 7, at 1161). Finally, the Company notes that as part of its proposal, a revenue credit has been applied to its cost of service in the amount of $364,756 ($28.00 x 13,027) (Exhs. NG-RRP-1, at 19; NG-RRP-2, at 3 (Rev. 3); EFCA-1-6, at 2).

The Company states that the proposed application fee is an appropriate way to recover from DG customers the costs associated with the Simplified Process applications (Exh. EFCA-1-6, at 2). According to the Company, without the application fee, ratepayers would be at risk for these costs (Exh. EFCA-1-6, at 2).

3. Positions of the Parties

No party addressed the Company's proposal on brief. In its prefiled testimony, EFCA provided conditional support for the Company's proposal (Exh. EFCA-CG-1, at 29). However, EFCA submits that the application fee should be implemented in a manner that does not create an administrative burden or application delay due to the processing of payment (Exh. EFCA-CG-1, at 29). EFCA further maintains that the Company should make every effort to optimize the Simplified Process for applying for interconnection (Exh. EFCA-CG-1, at 29).

4. Analysis and Findings

The Department approved the current fee structure applicable to interconnecting DG customers in D.P.U. 11-75-E at 36. In that Order, the Department recognized that if electric distribution companies do not collect enough funds to cover the costs associated with the interconnection of DG, ratepayers risk paying for the unrecovered costs. D.P.U. 11-75-E at 36. The Department noted that such an outcome is inconsistent with the interconnection framework, whereby the interconnecting customers pay for costs associated with the applicable interconnection. D.P.U. 11-75-E at 36, citing D.T.E. 02-38-B at 13-14.

In the instant case, the Company has demonstrated that there has been a significant increase in Simplified Process applications in recent years (Exhs. NG-RRP-1, at 18-19; EFCA-1-6, at 2; Tr. 7, at 1163). The Company also has provided evidence of the nature of the tasks associated with processing the Simplified Process applications (Exh. DPU-29-12; Tr. 7, at 1161-1162). Given these considerations, we find that the Company is incurring costs associated with processing Simplified Process applications for which interconnecting DG customers should be responsible. Therefore, we find that an application fee is a reasonable and appropriate way to recover application-related costs from interconnecting customers and to prevent ratepayers from paying for any such unrecovered costs. See D.P.U. 11-75-E at 36; D.T.E. 02-38-B at 13-14. Further, while the Company's proposed $28.00 application fee may not be derived through a precise calculation of the specific costs associated with processing the Simplified Process applications, we conclude that the one-time fee is not so disproportionate to the scope of work necessary to process the applications as to render the fee unreasonable.

Finally, we acknowledge EFCA's concerns with respect to implementing the application fee and optimizing the Simplified Process for interconnection. However, there is nothing in the record that leads us to conclude that any further direction to the Company with respect to these concerns is warranted.

Based on these findings, we approve the Company's proposal to assess a one-time application fee of $28.00 for interconnecting DG customers that use the Simplified Process. In addition, the Department also approves the Company's proposed credit to revenues in the amount of $364,756. The Company is directed in its compliance filing to revise its Interconnection Tariff accordingly.

C. Summary of Charges Tariff

In the Company's last rate case, the Department directed National Grid to include a separate tariff that shows the approved charges for each rate class, which is referred to as the summary tariff. D.P.U. 09-39, at 442. The summary tariff is the sole tariff that states the current charges for each delivery service factor.[352] The Department found that the use of a summary tariff is administratively efficient, consumer-friendly, and consistent with Department precedent. See, e.g., D.P.U. 09-39, at 442; D.P.U. 07-71, at 197-198; D.T.E. 05-85, M.D.P.U. No. 190 (2005).

[352] The currently effective summary tariff shows for each rate class: (1) the M.D.P.U. number; (2) the applicable blocks of kWh hours use; (3) customer and other distribution charges; (4) other delivery service charges including pension and PBOP adjustment factor, RAAF, basic service adjustment, SFRF, revenue decoupling adjustment factor, solar cost adjustment factor, attorney general consultant expense factor, smart grid distribution adjustment factor, transition, transmission, renewable, and energy efficiency charges; and (5) the date of the last change of each rate (see M.D.P.U. Nos. 1-16-B, 1-16-C).

During the course of this proceeding, National Grid agreed to amend its standard summary tariff by including basic service pricing (Exh. DPU-18-11 & Atts.; Tr. 7, at 1183). Accordingly, the Department directs the Company in its compliance filing to include in its summary tariff, the basic service rates for each rate class, consistent with the summary tariffs for NSTAR Electric, Unitil, and WMECo, and to include the changes to the delivery service rates consistent with the directives in this Order (see M.D.P.U. Nos. 190-16-C, 290-16-C, 390-16-C (NSTAR Electric); 297 (Unitil); 1052-16-D (WMECo)).

D. Other Tariff Changes

The Company proposes changes to the following tariffs that are not addressed above or elsewhere in this Order: (1) Terms and Conditions for Distribution Service (proposed M.D.P.U. No. 1275); (2) Solar Cost Adjustment Provision (proposed M.D.P.U. No. 1281); (3) Optional Enhanced Metering Service (proposed M.D.P.U. No. 1283); and (4) Optional Interval Data Service (proposed M.D.P.U. No. 1284) (Exhs. NG-PP-1, at 79-80, 87; NG-PP-24, at 204-243, 275-278, 281-284). No party addressed the Company's proposed changes. The Department has reviewed the changes and we find that they are acceptable. National Grid, as part of its compliance filing, is directed to revise these tariffs accordingly.

National Grid also proposes changes to its Net Metering Provision (proposed M.D.P.U. No. 1279)[353] and its Standards for Interconnection of Distributed Generation (proposed

[353] The Company also proposes revisions to its Net Metering Provision and its Qualifying Facility Power Purchase Rate P (proposed M.D.P.U. No. 1286) to reflect the inclusion of the proposed Access Fee applicable to stand-alone DG facilities (Exhs. NG-PP-1, at 80; NG-PP-24, at 289-294). As discussed in Section XIV.A.3 above, the Department has rejected the proposed Access Fee and directed the Company to revise these tariffs accordingly.

M.D.P.U. No. 1285)[354] to implement the Company's proposal to bid capacity of customer-owned solar facilities in the forward capacity market (Exhs. NG-PP-1, at 80; NG-PP-24, at 257-272, 285-288). The proposed changes related to the forward capacity market are inconsistent with our findings in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, Interlocutory Order (February 9, 2016). Therefore, the Department disallows the proposed changes. The Company, as part of its compliance filing, is directed to revise these tariffs accordingly.

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354 The Company also proposes revisions to its Standards for Interconnection of Distributed Generation to reflect the inclusion of a $28 application fee for some interconnecting DG customers (Exhs. NG-PP-1, at 80; NG-PP-24, at 285-288). As discussed in Section XIV.B.4 above, the Department has allowed the application fee and directed the Company to revise this tariff accordingly.

XV. SCHEDULES

A. Schedule 1 – Revenue Requirements and Calculations of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	418,651,872	(6,301,828)	(18,305,155)	394,044,888
Depreciation & Amortization	126,675,702	0	6,690,139	133,365,841
Taxes Other Than Income Taxes	72,425,197	(2,462,861)	(463,672)	69,498,664
Interest on Customer Deposits	87,581	0	0	87,581
Income Taxes	64,398,568	190,633	(8,614,404)	55,974,797
Return on Rate Base	145,879,317	422,252	(11,141,024)	135,160,545
Additional Uncollectibles (Revenue Deficiency)	2,595,005	(114,982)	(395,894)	2,084,129
Total Cost of Service	830,713,242	(8,266,786)	(32,230,011)	790,216,446
OPERATING REVENUES				
Base Distribution Revenues	587,866,996	0	0	587,866,996
Other Operating Revenues	31,585,294	1,093,917	0	32,679,211
Total Operating Revenues	619,452,290	1,093,917	0	620,546,207
Total Revenue Deficiency	**211,260,952**	**(9,360,703)**	**(32,230,011)**	**169,670,239** *

*The Total Revenue Deficiency represents $101,000,617 in additional base distribution revenue and $68,669,622 currently recovered through reconciling charges and transferred for recovery in base distribution revenue in this proceeding.

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 – Operation and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Other Operation & Maintenance Expenses	378,462,961	(477,379)	0	377,985,582
Purchased Power	1,120,435,761	0	0	1,120,435,761
Transmission O&M	413,579,624	0	0	413,579,624
Environmental Response Fund	4,017,471	0	0	4,017,471
Storm Recovery Outside of Rate Base	44,675,247	0	0	44,675,247
Pension/OPEB Expense	31,789,638	0	0	31,789,638
Energy Efficiency O&M	264,485,767	477,379	0	264,963,146
Storm Fund	4,300,000	0	0	4,300,000
Uncollectible Accounts- Delivery Write-offs	62,292,694	0	0	62,292,694
	2,324,039,162	0	0	2,324,039,162
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Eliminate Tracked Items:				
Purchased Power	(1,119,347,926)	0	0	(1,119,347,926)
Transmission O&M	(423,091,751)	0	0	(423,091,751)
Energy Efficiency	(264,485,767)	(477,379)	0	(264,963,146)
Storm Recovery Outside of Rate Base	(44,675,247)	0	0	(44,675,247)
Pension / OPEB	(31,789,638)	0	0	(31,789,638)
Eliminate Commodity Procurement Administration Costs (Basic Service)	(579,215)	0	0	(579,215)
O&M Recovered Through Solar Phase II Cost Recovery Factors	(191,093)	0	0	(191,093)
O&M Recovered Through SmartGrid Cost Recovery Factors	(11,623,419)	0	0	(11,623,419)
Eliminate O&M Recovered Through Purchase of Receivables (POR) program	(404,429)	0	0	(404,429)
Rent Expense adjustment for Information System Projects & Facilities Expense	(3,259,652)	(2,314,286)	(195,172)	(5,769,110)
Eliminate General/Institutional Advertising	(157,453)	0	0	(157,453)
Eliminate Senior Executive Expenses	(122,772)	0	0	(122,772)
Eliminate Intercompany Equity Maintenance Agreement	(7,900,632)	0	0	(7,900,632)
Eliminate Rate Case Expense related to Docket No. DPU 09-39	(327,510)	0	0	(327,510)
One Time/Out of Period Adjustments	(2,339,447)	0	0	(2,339,447)
Paperless Billing Credit	859,993	0	0	859,993
Out-of-period Service Co allocation corrections	0	262,256	0	262,256
FAS 112	2,753,539	(416,331)	0	2,337,208
Airplane rental charge	0	(7,138)	0	(7,138)
Postage expense	0	(283,605)	0	(283,605)
Uncollectibles Expense	(43,633,220)	(1,043,371)	0	(44,676,591)
POST TEST YEAR ADJUSTMENTS:				
Salary and Wage Adjustments	10,996,071	(2,029,898)	(1,280,399)	7,685,773
Health Care Expense	(250,830)	(13,138)	(86,778)	(350,746)
Group Insurance Expense	111,969	(28,591)	(8,923)	74,455
Employee Thrift	393,144	(90,651)	(43,272)	259,220
Facilities and Information Systems Lease Expense	10,869,709	(742,205)	(134,915)	9,992,589
Overnight Personnel for Priority 1 & 2 Calls	108,120	(108,120)	0	0
Uninsured Claims	(447,281)	(459,778)	0	(907,059)
Insurance Premiums	(1,069,836)	36,602	0	(1,033,234)
Other O&M Inflation Adjustment	6,311,460	(998,556)	(1,029,279)	4,283,625
Rate Case Expense	302,557	(53,436)	0	249,121
Regulatory Assessments	0	1,006,497	0	1,006,497
MECO IFA Expenses	(394,628)	(799,344)	0	(1,193,973)
Environmental Response Fund	176,367	(25,310)	(17,677)	133,380
Storm Fund	9,700,000	0	(5,103,257)	4,596,743
Hardship Protected Accounts*	8,121,527	2,283,955	(10,405,483)	0
Sum of O&M Expense Adjustments	(1,905,387,291)	(6,301,828)	(18,305,155)	(1,929,994,274)
Total O&M Expense	**418,651,872**	**(6,301,828)**	**(18,305,155)**	**394,044,888**

*Hardship Expense moved to Schedule 3

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	126,675,702	0	(1,431,389)	125,244,313
Hardship Protected Accounts*	0	0	8,121,527	8,121,527
Total Depreciation and Amortization Expense	**126,675,702**	**0**	**6,690,139**	**133,365,841**

*From Schedule 2

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

D. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	3,995,978,017	0	(332,000)	3,995,646,017
LESS:				
Reserve for Depreciation	1,687,662,861	(3,345,864)	0	1,684,316,997
Net Utility Plant in Service	2,308,315,156	3,345,864	(332,000)	2,311,329,020
ADDITIONS TO PLANT:				
Materials and Supplies	24,453,573	(1,222,533)	(378,821)	22,852,219
Cash Working Capital	72,905,019	(4,885,103)	(15,695,830)	52,324,086
Total Additions to Plant	97,358,592	(6,107,636)	(16,074,651)	75,176,305
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	577,103,094	(7,955,529)	0	569,147,565
Customer Deposits	29,839,942	0	0	29,839,942
Customer Advances	4,397,172	0	0	4,397,172
Total Deductions from Plant	611,340,208	(7,955,529)	0	603,384,679
RATE BASE	1,794,333,540	5,193,757	(16,406,651)	1,783,120,647
COST OF CAPITAL	8.13%	8.13%	-0.55%	7.58%
RETURN ON RATE BASE	**145,879,317**	**422,252**	**(11,141,024)**	**135,160,545**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 5 – Cost of Capital

PER COMPANY	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,235,000,000	47.93%	5.56%	2.670%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% *
Common Equity	$1,339,156,000	51.98%	10.50%	5.460%
Total Capital	$2,576,415,000	100.00%		8.13%
Weighted Cost of				
Debt				2.67%
Preferred				0.00%
Equity				5.46%
Cost of Capital				8.13%

COMPANY ADJUSTMENTS	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,235,000,000	47.93%	5.56%	2.670%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% *
Common Equity	$1,339,156,000	51.98%	10.50%	5.460%
Total Capital	$2,576,415,000	100.00%		8.13%
Weighted Cost of				
Debt				2.67%
Preferred				0.00%
Equity				5.46%
Cost of Capital				8.13%

PER ORDER	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$1,300,000,000	49.22%	5.21%	2.560%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% **
Common Equity	$1,339,156,000	50.70%	9.90%	5.020%
Total Capital	$2,641,415,000	100.00%		7.58%
Weighted Cost of				
Debt				2.56%
Preferred				0.00%
Equity				5.02%
Cost of Capital				7.58%

*0.003893%

**0.003797%

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F. Schedule 6 – Cash Working Capital

	CWC%	PER COMPANY	CWC%	COMPANY ADJUSTMENT	CWC%	DPU ADJUSTMENT	PER ORDER
O&M Subject to Cash Working Capital	5.90%	378,462,961	-0.06%	(2,684,767)	0%	(2,583,566)	373,194,627
Energy Efficiency	5.90%	264,485,767	-0.06%	477,379	0%	(264,963,146)	0
CTC Expense	1.88%	(2,887,862)	0.00%	11,958	0%	0	(2,875,904)
Transmission O&M	6.21%	413,579,624	0.00%	13,242,461	0%	0	426,822,085
Total		1,053,640,490		11,047,031		(267,546,712)	797,140,809
Taxes Other than Income Taxes							
Municipal Taxes	4.99%	56,269,342	0.04%	4,107,023	0%	(1,344,207)	59,032,158
Payroll Taxes - Company Portion							
Federal Unemployment	-12.42%	56,065	-0.04%	18,689	0%	(184)	74,570
State Unemployment	-13.40%	219,968	-0.10%	34,888	0%	(724)	254,132
FICA Expense - Weekly	9.40%	8,326,349	-0.02%	583,071	0%	(27,397)	8,882,023
FICA Expense - Monthly	7.21%	1,105,863	-0.03%	63,740	0%	(3,639)	1,165,964
Total		65,977,587		4,807,411		(1,376,151)	69,408,848
Payroll Taxes and Other Withholding							
FICA and Federal Withholding - Weekly	11.50%	27,271,963	-10.95%	(4,927)	0%	(89,735)	27,177,301
FICA and Federal Withholding - Monthly	12.49%	3,385,469	-10.90%	(11,875)	0%	(11,139)	3,362,455
State Income Tax Withholding - Weekly	-0.53%	5,585,890	1.07%	0	0%	(18,380)	5,567,510
State Income Tax Withholding - Monthly	-1.56%	701,277	3.15%	0	0%	(2,307)	698,970
Incentive Thrift - Weekly	10.88%	17,555,926	-10.93%	0	0%	(57,766)	17,498,160
Incentive Thrift - Monthly	10.99%	2,543,862	-10.99%	0	0%	(8,370)	2,535,492
Total		57,044,387		(16,802)		(187,697)	56,839,888
Amount Subject to Cash Working Capital		1,176,662,464		15,837,640		(269,110,560)	923,389,544
Total Cash Working Capital Allowance		**72,905,019**		**(4,885,103)**		**(15,695,830)**	**52,324,086**
Composite Lead Lag Factor				**5.70%**			**5.67%**

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G. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Municipal Tax	56,269,342	0	0	56,269,342
Payroll Tax	10,748,283	0	0	10,748,283
Other Taxes	3,496,809	0	0	3,496,809
Test Year Municipal Taxes	70,514,434	0	0	70,514,434
ADJUSTMENTS TO TAXES OTHER THAN INCOME:				
Normalizing adjustments:				
Municipal Tax	675,476	0	0	675,476
Payroll Tax	0	(564,304)	(163,969)	(728,273)
Other Taxes	(3,383,264)	0	0	(3,383,264)
Known & measurable adjustments:				
Municipal Tax	3,799,326	(1,467,955)	(244,031)	2,087,340
Payroll Tax	819,226	(430,602)	(55,672)	332,952
Total Adjustments	1,910,764	(2,462,861)	(463,672)	(1,015,769)
Total Municipal Tax	60,744,144	(1,467,955)	(244,031)	59,032,158
Total Payroll Tax	11,567,509	(994,906)	(219,641)	10,352,962
Total Other Tax	113,545	0	0	113,545
Taxes Other Than Income	**72,425,197**	**(2,462,861)**	**(463,672)**	**69,498,664**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

H. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	1,794,333,540	5,193,757	(16,406,651)	1,783,120,647
Return on Rate Base	145,879,317	422,252	(11,141,024)	135,160,545
Less:				
Interest Expense	47,908,706	138,673	(2,399,490)	45,647,889
Amort. Net Unfunded Deferred Tax Liability	440,768	0	1,637,317	2,078,085
Income Tax Impact of Flow Through Items	(274,007)	0	0	(274,007)
Amortization of Investment Tax Credits	707,081	0	0	707,081
Total Deductions	48,782,548	138,673	(762,173)	48,159,048
Taxable Income Base	97,096,769	283,579	(10,378,851)	87,001,497
Gross Up Factor*	1.6722	1.6722	1.6722	1.6722
Taxable Income	162,369,179	474,213	(17,355,938)	145,487,454
Mass Franchise Tax 8%	12,989,534	37,937	(1,388,475)	11,638,996
Federal Taxable Income	149,379,645	436,276	(15,967,463)	133,848,458
Federal Income Tax at 35%	52,282,876	152,696	(5,588,612)	46,846,960
Amort. Net Unfunded Deferred Tax Liability	(440,768)	0	(1,637,317)	(2,078,085)
Income Tax Impact of Flow Through Items	274,007	0	0	274,007
Amortization of Investment Tax Credits	(707,081)	0	0	(707,081)
Total Income Taxes	**64,398,568**	**190,633**	**(8,614,404)**	**55,974,797**

*1.672240803

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

I. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
DISTRIBUTION REVENUES PER BOOKS	587,866,996	0	0	587,866,996
Other Operating Revenues	29,548,876	0	0	29,548,876
Adjustments to Other Operating Revenues				
Returned Check fee	0	8,516	0	8,516
Gain on sale of property	0	318,689	0	318,689
Pole Attachment Fees	0	766,712	0	766,712
Miscellaneous Fees	(27,570)	0	0	(27,570)
DG Application Fee	364,756	0	0	364,756
Solar Phase I Revenue	1,699,232	0	0	1,699,232
Total Adjustments	2,036,418	1,093,917	0	3,130,335
Total Other Revenues	31,585,294	1,093,917	0	32,679,211
Adjusted Total Operating Revenues	**619,452,290**	**1,093,917**	**0**	**620,546,207**

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J. Schedule 10 – Allocation to Rate Classes

For illustrative purposes only

Department Approved Revenue Increase 169,670,239

Rate Class	Per Final Revenue Allocation: Proposed COSS Target Revenue (1)	Per Final Revenue Allocation: Current Revenue (2)	Per Final Revenue Allocation: Proposed Deficiency at EROR (3)	Per Final Revenue Allocation: Percent Increase at EROR (4)	Total Revenue Based on Current Rates (5)	Department Approved Revenue Increase at EROR (6)	Percent Increase at Department Approved Revenue Increase (7)	Section 20 Revenue Increase Cap (8)	Excess Increase to be Re-allocated (9)	Per Order Re-allocation to Uncapped Rate Classes (10)	Uncapped and Re-allocated Department Approved Revenue Increase (11)	Per Order Revenue to be Re-allocated 200% Cap (12)	Per Order Re-allocation to Uncapped Rate Classes (13)	Department Approved Revenue Requirement (14)	Department Approved Revenue Increase (15)
Residential R-1/R-2	$444,918,329	$314,481,570	$130,436,759	41.48%	$1,893,254,281	$107,558,481	34.20%	$189,325,428	$0	$6,372,692	$113,931,174	$0	$39,453	$428,452,197	$113,970,627
Residential R-4	$748,283	$336,782	$411,501	122.19%	$2,624,869	$373,284	110.84%	$262,487	$110,797		$262,487	$68,083	$0	$531,185	$194,404
Small C&I G-1	$94,857,778	$101,635,361	($6,777,583)	-6.67%	$466,269,132	($11,667,548)	-11.48%	$46,626,913	$0	$1,358,490	($10,309,058)	$0	$8,410	$91,334,714	($10,300,647)
Medium C&I G-2	$90,220,476	$56,293,156	$33,927,320	60.27%	$504,774,535	$29,175,068	51.83%	$50,477,454	$0	$1,290,547	$30,465,615	$0	$7,990	$86,766,761	$30,473,605
Large C&I G-3	$138,402,752	$101,210,034	$37,192,718	36.75%	$1,231,863,068	$29,614,935	29.26%	$123,186,307	$0	$1,975,422	$31,590,357	$0	$12,230	$132,812,622	$31,602,587
Street Lighting	$29,980,323	$13,910,094	$16,070,229	115.53%	$37,296,584	$14,616,012	105.07%	$3,729,658	$10,886,354		$3,729,658	$0	$0	$17,639,752	$3,729,658
Total Company	$799,127,941	$587,866,997	$211,260,944	35.94%	$4,136,082,470	$169,670,234	28.86%	$413,608,247	$10,997,152	$10,997,152	$169,670,234	$68,083	$68,083	$757,537,231	$169,670,234

Notes:

(1) Exhibit DPU-33-8, Att. at 37, line 24
(2) Exhibit DPU-33-8, Att. at 37, line 1
(3) Column (1) - Column (2)
(4) Column (3) ÷ Column (2)
(5) Exhibit DPU-33-8, Att. at 37, line 21 / Test Year Billing Determinants multiplied by current rates for each rate class.
(6) Per Cost of Service Study
(7) Column (6) ÷ Column (2)
(8) Column (5) x 10%
(9) If Column (8) > Column (6), then $0. If Column (8) < Column (6), then Column (6) - Column (8)
(10) [(Column (2) + Column (6) for applicable rate class) ÷ (sum of Column (2) + Column (6) for uncapped rate classes)] x Total Column (9)
(11) Column (6) - Column (9) + Column (10)
(12) If [Column (11) / Column (2)] > 2*[Total of Column (7)], then Column (11) - [Column (2) * (2*Total of Column (7)]. If not, then zero.
(13) [(Column (2) + Column (6) for applicable rate class) ÷ (sum of Column (2) + Column (6) for uncapped rate classes)] x Total Column (12)
(14) Column (2) + Column (11) + Column (13)
(15) Column (14) - Column (2)

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

XVI. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That tariffs M.D.P.U. Nos. 1264 through 1286, as applicable to Massachusetts Electric Company, and tariffs M.D.P.U. Nos. 576 through 587 and M.D.P.U. Nos. 1275 through 1286, as applicable to Nantucket Electric Company, filed on November 6, 2015, to become effective, after suspension by the Department, on October 1, 2016, 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 $169,670,239; 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 orders and directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after the date of this Order, 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/

Angela M. O’Connor, Chairman

/s/

Robert E. Hayden, Commissioner

XVII. PARTIAL DISSENT OF COMMISSIONER WESTBROOK

While I join with the majority's conclusions for much of this decision, I dissent specifically from the conclusions found in Sections V.D.4 and XII.E above, with respect to the inclusion of property taxes in the Company's CIRM and the ROE. For the reasons below, I am of the opinion that the Department should not expand National Grid's CIRM to include recovery of property taxes. The Department recently excluded property taxes from the capital cost recovery mechanism approved for Fitchburg Gas and Electric Light Company (Electric Division) ("Fitchburg"), and I see no reason to treat National Grid's proposal differently.[355]

In D.P.U. 09-39, the Department approved a reconciling mechanism, then referred to as the capital expenditures ("CapEx") mechanism, which allowed the Company to recover an annual revenue requirement on incremental capital investments. D.P.U. 09-39, at 80. We did so, recognizing that revenue decoupling would remove the Company's opportunity to earn additional revenue to fund projected capital expenditures from growth in sales between rate proceedings. D.P.U. 09-39, at 79-80. National Grid's CapEx does not provide for inclusion of property taxes in the recovery mechanism. In D.P.U. 15-80/D.P.U. 15-81, at 52, we approved a capital investment recovery mechanism for Fitchburg that was designed to operate similar to National Grid's CapEx mechanism. One way in which the Department revised Fitchburg's CCAM to make it consistent with National Grid's CapEx was the exclusion of property taxes from the calculation of Fitchburg's CCAM. D.P.U. 15-80/D.P.U. 15-81, at 55-56.

In this Order, the Department finds that National Grid has adequately demonstrated a continued need to recover incremental costs associated with capital expenditure programs

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[355] Fitchburg's capital investment recovery mechanism approved by the Department is the capital cost adjustment mechanism ("CCAM"). D.P.U. 15-80/D.P.U. 15-81, at 1.

between base distribution rate proceedings (see Section V.D above). In approving National Grid's CIRM, this Order, however, modifies the existing CapEx in three ways. First, the Department has increased the investment cap from $170 million to $249 million, allowing the Company to recover more of its capital investment between rate cases. Second, the Department has removed the CIRM from the RDM tariff, thereby separating the rate caps and allowing the Company further latitude to recover costs associated with capital investments between rate cases. Third, the majority has found it appropriate to include the recovery of property taxes associated with capital investments as part of the CIRM allowing the Company to recover property tax expense outside of the $249 million investment cap. While I find the first two modifications to be appropriate, I am of the opinion that including property taxes in the CIRM has expanded this mechanism beyond its original purpose and that such expansion is not in the best interests of ratepayers.

Previously, the Department has only allowed capital investment recovery mechanisms upon a finding that the mechanism strikes the appropriate balance between: (1) providing a company with sufficient funds to ensure safe and reliable electric service; and (2) protecting ratepayers from overinvestment in capital infrastructure. D.P.U. 09-39, at 81-82; D.P.U. 15-80/D.P.U. 15-81, at 51. As noted above, the Department rejected a similar proposal by Fitchburg to include property taxes in the calculation of its capital cost recovery mechanism. D.P.U. 15-80/D.P.U. 15-81, at 54. In that case, the Department stated that the revised CCAM, including the exclusion of property taxes in the calculation of the capital cost recovery mechanism, strikes an appropriate balance of providing Fitchburg with a source of funds to invest in capital expansion projects between rate cases, while protecting ratepayers from the

Company's incentive to over-invest. D.P.U. 15-80/D.P.U. 15-81, at 54. See also D.P.U. 07-50-A at 48. Further, the Department explained that the purpose of a capital cost recovery mechanism is not to provide a company with dollar-for-dollar recovery of capital investments between rate cases, but to provide rate relief in between base distribution rate cases to fund capital investments that were available to be funded through sales growth prior to decoupling. D.P.U. 15-80/D.P.U. 15-81, at 54. Thus, in my opinion, the inclusion of property taxes in the National Grid's CIRM is contrary to the intended goal of capital investment recovery mechanisms. I continue to support that concept of the CIRM and conclude that excluding property taxes strikes the appropriate balance.

In this case, I do not believe that excluding property taxes in the calculation of the CIRM will adversely affect the Company's financial well-being. The Company would recover its property taxes expense under traditional ratemaking as an O&M expense in the Company's cost of service. Moreover, while the need for a capital cost recovery mechanism is specific to each company, I see no evidence in the record that warrants different treatment between Fitchburg and National Grid with respect to the underlying policy goals of a capital investment recovery mechanism.

I disagree with the majority that "exclusion of [property taxes] does not provide the appropriate rate relief between base rate proceedings" (see page 57 above). By increasing the investment cap and separating the CIRM and RDM rate caps, the Department has provided sufficient support for the Company to fund its capital expenditures. Additionally, including recovery of property taxes through the CIRM, in my opinion, provides the Company with more than adequate funding to compensate for the effect of decoupling.[356] While the majority notes that the inclusion of a portion of property taxes in National Grid's CIRM does not constitute dollar-for-dollar recovery (see page 58 above), it is my opinion that the inclusion of property taxes expands the CIRM beyond the intended purpose aligning it more with a dollar-for-dollar recovery mechanism.

Further, unlike the gas companies' targeted capital investment recovery factors that include property tax recovery (e.g., TIRF, GSEP),[357] the Company's CIRM is broad. The TIRF and the GSEP programs are more narrow, focus on a specific public safety issue identified by the Legislature, and the GSEPs require the Department's approval of a capital investment plan. See, e.g., Boston Gas Company/Colonial Gas Company, D.P.U. 14-132, at 3-5 (2015). Under the CIRM, however, the Company can recover any and all capital investments under the investment cap that are not recovered through another factor. Expanding the already broad CIRM to include property taxes is not necessary for the intended purpose of capital investment recovery mechanisms and will result in annual cost increases for ratepayers.

Lastly, the majority finds that an ROE of 9.90 percent is appropriate (see Section XII.E above). While I agree that 9.90 percent is within the range of reasonableness, I believe that a downward adjustment to the ROE that would still remain within the range of reasonableness is appropriate to more fully reflect the reduced risk to the Company as a result the CIRM, including property taxes, and our treatment of protected hardship account balances in Section VIII.J.3.

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356 A utility can file a base rate case with the Department under G.L. c. 164, § 94 if the utility determines that it is not earning sufficient revenues to fund its operations.

357 Targeted Infrastructure Recovery Mechanism ("TIRF"); Gas System Enhancement Plan ("GSEP").

Apart from these points and their consequences for other features of the final Order in this docket, I join in the remainder of the decision.

/s/

Jolette A. Westbrook, 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.