The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 10-55 November 2, 2010

Petition of Boston Gas Company, Essex Gas Company and Colonial Gas Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates, a Targeted Infrastructure Recovery Factor, and a Revenue Decoupling Mechanism.

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I. INTRODUCTION

On April 16, 2010, Boston Gas Company ("Boston Gas"), Essex Gas Company ("Essex Gas"), and Colonial Gas Company ("Colonial Gas"), each doing business as National Grid (collectively as "National Grid"[1] or "Companies") filed a petition with the Department of Public Utilities ("Department") for a $106,043,447 increase in gas distribution rates pursuant to G.L. c. 164, § 94. In the initial filing, Boston Gas and Essex Gas seek approval of a combined revenue increase of $79,232,386 to reflect the merger of both entities, as approved by the Department in Boston Gas Company-Essex Gas Company, D.P.U. 09-139 (2010).[2] Colonial Gas' proposed revenue increase of $26,811,061 is based on a single revenue requirement that eliminates the historical separation between its Cape Cod and Lowell divisions.[3]

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1 The Department notes that National Grid is not a separate corporate entity, and the collective reference to the petitioners as National Grid is simply for administrative ease.

2 Boston Gas is currently operating under a performance-based rate ("PBR") plan approved by the Department in Boston Gas Company, D.T.E. 03-40 (2003), and set to expire on October 31, 2013. Base distribution rates for Boston Gas customers were set in D.T.E. 03-40 and have been adjusted on an annual basis since the implementation of the PBR plan in 2003. Essex Gas was last granted a base rate increase in Essex Gas Company, D.P.U. 96-107 (1996). Subsequently, in 1998, the Department approved a ten year freeze of those rates in Eastern-Essex Acquisition, D.T.E. 98-27 (1998). The rate freeze expired in 2008. As noted above, in D.P.U. 09-139, the Department approved the merger of Boston Gas and Essex Gas, with Boston Gas as the surviving entity. This merger was completed effective November 1, 2010 (see D.P.U. 09-139, Compliance Filing, Appendix 1 (October 13, 2010)).

3 Colonial Gas was last granted a base distribution rate increase in Colonial Gas Company, D.P.U. 93-78 (1993). Subsequently, in 1999, the Department approved a ten year freeze of those rates in Eastern-Colonial Acquisition, D.T.E. 98-128 (1999). The rate freeze expired in 2009. Colonial Gas has maintained a separate rate structure

In addition to a base distribution rate increase, National Grid seeks approval of: (1) the termination of Boston Gas' PBR plan; (2) a revenue decoupling mechanism; (3) a targeted infrastructure recovery factor ("TIRF") intended to recover the costs associated with an accelerated replacement of cast-iron and steel mains and other associated facilities; (4) a surcharge to fund energy efficiency-related technology and innovation ("T&I") projects; and (5) a net inflation adjustment factor to adjust distribution rates on an annual basis to account for the impact of inflation and productivity between rate cases.

The Department docketed this matter as D.P.U. 10-55. It has suspended the effective date of the proposed rate increase until November 2, 2010, to investigate the propriety of National Grid's request.

As noted above, Boston Gas and Essex Gas seek approval of a combined revenue increase to reflect the merger of both entities and Colonial Gas seeks approval of a revenue increase based on a single revenue requirement that eliminates the historical separation between its Cape Cod and Lowell divisions. For the reasons set forth in Section XII.D.3 below, the Department finds that it is appropriate to combine the residential rate structures of Boston Gas and Essex Gas. Further, the Department finds that it is appropriate to combine the residential rate structures and the commercial and industrial ("C&I") rate structures of Colonial Gas' Lowell and Cape Cod divisions. Accordingly, the Department has analyzed National Grid's proposed adjustments to test year revenues and costs based on these combined revenue

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for customers in its Cape Cod and Lowell divisions since 1981, after the merger of Cape Cod Gas Company and Lowell Gas Company, pursuant to Lowell Gas Company/Cape Cod Gas Company/Colonial Energy System, D.P.U. 514/515 (1981).

requirements. Further, the various adjustments approved by the Department herein reflect the combined Boston Gas and Essex Gas entities and the combined Colonial Gas entity. Throughout the remainder of this Order, unless otherwise noted, the Department will refer to the combined Boston Gas and Essex Gas entity as "Boston Gas-Essex Gas," and the combined Colonial Gas entity (i.e., the Lowell and Cape Cod divisions) as "Colonial Gas." When referring to Boston Gas-Essex Gas and Colonial Gas collectively the Department will use the term "National Grid" or "Companies."

II. PROCEDURAL HISTORY

On April 20, 2010, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E. On May 14, 2010, the Department granted the petition of NSTAR Gas Company for limited participant status. On May 17, 2010, the Department granted intervenor status to the Massachusetts Department of Energy Resources ("DOER"). On May 25, 2010, the Department granted intervenor status to Environment Northeast ("ENE") and limited participant status to Bay State Gas Company and Blackstone Gas Company. On June 2, 2010, the Department granted intervenor status to the Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association (together, "Low-Income Intervenors"), Locals 350 and 369 of the Utility Workers Union of America ("UWUA"), The Energy Network ("TEN"), the New England Gas Workers Association ("NEGWA"), and Hess Corporation. On that same date, the Department granted limited participant status to Western Massachusetts Electric Company.

Pursuant to notice duly issued, the Department held seven public hearings in the Companies' service areas: (1) in Barnstable on May 25, 2010; (2) in Acton on May 26, 2010; (3) in Boston on May 27, 2010; (4) in Haverhill on June 1, 2010; (5) in Quincy on June 2, 2010; (6) in Lynn on June 3, 2010; and (7) in Lowell on June 7, 2010. The Department held 20 days of evidentiary hearings between June 28, 2010 and July 30, 2010. The Department received written comments from several public officials and a number of National Grid ratepayers.

On April 23, 2010, the Attorney General filed a Notice of Retention of Experts and Consultants, pursuant to G.L. c. 12, § 11E(b), as amended by St. 2008, c. 169 ("Green Communities Act"). On May 27, 2010, the Department approved the Attorney General's retention of experts and consultants. Boston Gas Company, et al., D.P.U. 10-55, Order on Notice of Attorney General to Retain Experts and Consultants (2010).

In support of its filing, National Grid sponsored the testimony of 14 witnesses: (1) Nickolas Stavropoulos, executive vice president of U.S. Gas Distribution for National Grid USA; (2) James B. Howe, senior vice president, U.S. Network Strategy for National Grid Corporate Services LLC; (3) William J. Akley, senior vice president, U.S. Gas Operations and Construction for National Grid USA; (4) Susan F. Tierney, managing principal, Analysis Group; (5) Michael D. LaFlamme, vice president, Regulation and Pricing for Electric Distribution and Generation for National Grid USA Service Company, Inc.; (6) Lawrence R. Kaufmann, senior advisor, Pacific Economics Group, LLC; (7) Paul R. Moul, managing consultant, P. Moul & Associates; (8) Mark E. Smith, vice president, Human

Resources, National Grid USA; (9) Amy Smith, director, Rate Case Strategy for U.S. Gas Distribution, National Grid Corporate Services, LLC; (10) Paul M. Normand, principal, Management Applications Consulting, Inc.; (11) Ronald J. Amen, vice president, Concentric Energy Advisors; (12) James D. Simpson, vice president, Concentric Energy Advisors; (13) Ann E. Leary, manager of pricing, National Grid; and (14) Stan Blazewicz, vice president, Global Head of Technology, National Grid USA Service Company, Inc.

The Attorney General sponsored the testimony of seven witnesses: (1) David E. Dismukes, consulting economist, Acadian Consulting Group; (2) David J. Effron, consultant; (3) C. John Meeske, president, Energy Market Decisions, Inc.; (4) Timothy Newhard, financial analyst, Office of Ratepayer Advocacy, Attorney General; (5) Alvaro E. Pereira, senior consultant, La Capra Associates, Inc.; (6) Lee Smith, managing consultant and senior economist, La Capra Associates; (7) J. Randall Woolridge, professor of finance and Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in business administration, University Park Campus, Pennsylvania State University. NEGWA sponsored the testimony of its chairman and president, Mark McDonald.

DOER submitted its initial brief on August 20, 2010. The Attorney General, ENE, Low Income Intervenors, UWUA, TEN, and NEGWA submitted initial briefs on August 23, 2010. National Grid submitted its initial brief on September 8, 2010. The Attorney General, ENE, Low Income Intervenors, UWUA, TEN, and NEGWA submitted reply briefs on

September 15, 2010. National Grid submitted its reply brief on September 23, 2010.[4] The evidentiary record consists of approximately 3,400 exhibits and responses to 249 record requests.

III. TERMINATION OF BOSTON GAS' PERFORMANCE-BASED REGULATION PLAN

A. Plan Description

In Boston Gas Company, D.P.U. 96-50 (Phase I) (1996), the Department established a PBR plan for Boston Gas to replace the traditional cost-of-service/rate-of-return method for setting the company's distribution rates. The initial term of the PBR plan was five years. D.P.U. 96-50 (Phase I) at 320.[5]

In Boston Gas Company, D.T.E. 03-40 (2003), Boston Gas proposed a new PBR plan. The components of the proposed PBR were similar to those approved in D.P.U. 96-50, with a price-cap formula as the primary component. D.T.E. 03-40, at 436-437. The Department approved the new PBR for Boston Gas but for a ten-year term,[6] with the last PBR adjustment to take place on November 1, 2013. D.T.E. 03-40, at 495-496, 508.

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4 On October 1, 2010, the Attorney General filed a motion to strike the three appendices attached to National Grid's reply brief and a portion of page 14 of that brief. On October 8, 2010, National Grid filed an opposition to the Attorney General's motion. In reaching our conclusions herein, the Department has not relied on the information found in the appendices, or the disputed portion of National Grid's reply brief. As such, the Attorney General's motion is moot.

5 Boston Gas was the first gas or electric utility company in the Commonwealth to be subject to a PBR plan. See D.T.E. 03-40, at 436 n. 185.

6 Boston Gas proposed a five-year term. D.T.E. 03-40, at 437.

Boston Gas' PBR formula provides for an annual adjustment to the company's rates by taking the previous year's normalized base distribution revenues (after service quality penalty adjustments) and increasing that number by a factor comprising an inflation index minus a productivity growth offset, plus an exogenous cost factor (when applicable). D.T.E. 03-40, at 471-497. Since the Department's Order in D.T.E. 03-40, Boston Gas has made six annual PBR compliance filings. Boston Gas Company, D.T.E. 04-88 (2004); Boston Gas Company, D.T.E. 05-66 (2005); Boston Gas Company, D.T.E. 06-78 (2006); Boston Gas Company, D.T.E. 07-73 (2007); Boston Gas Company, D.T.E. 08-67, Letter Order (2008); Boston Gas Company, D.T.E. 09-86, Letter Order (2009).

B. National Grid's Proposal

National Grid proposes to terminate Boston Gas' existing PBR plan and instead: (1) implement a revenue decoupling mechanism; (2) apply a net inflation adjustment to its operations and maintenance ("O&M") costs; and (3) implement the TIRF, which is designed to recover costs associated with distribution main and services replacement (Exh. NG-NS-1, at 9-10). The details of these three proposals are discussed in Sections IV, V, and VI, below.

C. Positions of the Parties

1. Attorney General

The Attorney General argues that rates produced by Boston Gas' current PBR plan are lawful and presumed just and reasonable and that Boston Gas may petition the Department to terminate its plan only under extraordinary financial circumstances (Attorney General Brief at 15). According to the Attorney General, Boston Gas is prohibited from filing a new rate increase until the expiration of its current PBR plan except under specific exigent economic circumstances that are not implicated by the Department's decoupling precedent (Attorney General Brief at 16, citing Bay State Gas Company, D.P.U. 07-89 (2008)).

The Attorney General claims that there are constitutional and concomitant statutory limits on the Department's power to set rates so that rates are neither confiscatory nor exorbitant, regardless of the ratemaking methods employed (Attorney General Brief at 16, citing Permian Basin Area Rate Cases, 390 U.S. 747, 769 (1968); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602-603 (1944); Washington Gas Light Co. v. Baker, 188 F.2d 11, 15 (D.C. Cir. 1950) cert. denied 340 U.S. 952 (1951)). According to the Attorney General, the Department must carefully balance the investor and consumer interests in permitting a reasonable return on the utility's investment (Attorney General Brief at 16, citing Bluefield Water Works & Improvement Co. v. Public Service Commission, 262 U.S. 679, 692-93 (1923) ("Bluefield"); Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234 (2002); New England Telephone & Telegraph v. Department of Public Utilities, 360 Mass. 443, 472 (1971)). Against this background, the Attorney General argues that National Grid has failed to establish that Boston Gas' PBR plan should be terminated or modified for any reason (Attorney General Brief at 17).

The Attorney General asserts that the PBR plan has been functioning correctly in terms of providing adequate revenues for Boston Gas to operate a safe and reliable system while providing returns to its shareholders (Attorney General Brief at 17-18, citing Exh. AG-AEP at 6; Tr. 18, at 2666-2668). Further, the Attorney General argues that Boston Gas' target returns are within the deadband established by the PBR plan and, therefore, are just and reasonable (Attorney General Brief at 18, citing Tr. 18, at 2663; Attorney General Reply Brief at 5). The Attorney General notes that National Grid did not present any independent quantitative analysis to determine if terminating Boston Gas' PBR plan was appropriate, and National Grid conceded that the PBR plan is functioning as designed within the earnings deadband (Attorney General Brief at 19-20, citing Tr. 16, at 2108, 2119-2121; Attorney General Reply Brief at 6).

Further, the Attorney General argues that the continued operation of the PBR plan would not conflict with the objectives of the Green Communities Act or any related energy efficiency incentives (Attorney General Brief at 18-19, citing Exh. AG-AEP at 12). The Attorney General also contends that National Grid has failed to demonstrate that its ability to attract capital has been impaired or that there will be any confiscation if the PBR plan continues (Attorney General Brief at 19). On this latter point, the Attorney General asserts that Boston Gas' 2009 annual report to the Department fails to reveal confiscation of property or extraordinary economic circumstances, as evidenced by its earned return on equity (Attorney General Reply Brief at 5-6, citing Boston Gas Company's 2009 Annual Return to the Department, Return on Average Common Equity). Further, the Attorney General contends that earnings-related issues could have been remedied by an earnings sharing filing made pursuant to the PBR plan and, therefore, Boston Gas' earnings do not justify the termination of the PBR plan (Attorney General Reply Brief at 6-9).

Finally, the Attorney General argues that terminating the PBR plan in favor of a cost of service ratemaking model would harm customers of Boston Gas (Attorney General Brief at 20; Attorney General Reply Brief at 4-5). The Attorney General contends that the cost to customers of termination of the rate plan would be over $358 million or, on average, more than $580 per customer (Attorney General Brief at 20, citing Exh. AG-TN at 3; Attorney General Reply Brief at 2).

2. National Grid

National Grid argues that its ability to seek termination of Boston Gas' PBR plan is provided by both statute and Department precedent (National Grid Brief at II.2, citing G.L. c. 164, § 94; Bay State Gas Company, D.P.U. 09-30, at 21 (2009); D.T.E. 03-40, at 496-497 & n.263; National Grid Reply Brief at 12-13). According to National Grid, it has the substantive right to seek new, just and reasonable rates at any time, even during the term of a PBR plan (National Grid Brief at II.3, citing Investigation Into Rate Structures that will Promote the Efficient Deployment of Demand Resources, D.P.U. 07-50-B at 37 (2008); National Grid Reply Brief at 13-15). Moreover, National Grid claims that the Attorney General implicitly accepted that G.L. c. 164, § 94 permits the filing of a rate case during the term of a PBR plan (National Grid Reply Brief at 13-14, citing D.P.U. 96-50).

National Grid states that its decision to seek termination of Boston Gas' PBR plan is based on several considerations. First, National Grid argues that its proposal is made in compliance with the Department's directives in Investigation Into Rate Structures that will Promote the Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 84 (2008), for all distribution companies to be operating under decoupling plans by December 31, 2012 (Exh. NG-NS-1, at 10). National Grid contends that the Department emphasized a need to implement decoupling mechanisms through a base rate proceeding so that those mechanisms would be initiated with a clear understanding of the utility's underlying distribution revenue requirement and allocation of the revenue requirement among customer classes through an allocated cost of service study (Exh. NG-NS-1, at 10, citing D.P.U. 07-50-A at 81). National Grid asserts that, in order to implement a revenue decoupling plan within the Department's expected timeframe, it was necessary to seek termination of Boston Gas' PBR plan, which currently extends through November 30, 2013, in order to file the required base rate proceeding (Exh. NG-NS-1, at 10).

Second, National Grid argues that, although the PBR plan approved by the Department in D.T.E. 03-40 is structured to provide both incentives for long-term cost reductions that will benefit customers and a measure of cost recovery to account for annual inflation, the PBR plan is not adequately structured to provide for timely recovery of incremental capital investments made for safety and reliability purposes (Exh. NG-NS-1, at 10-11). According to National Grid, the structure of Boston Gas' PBR plan makes it difficult to maintain an adequate return and attract the capital necessary to fund infrastructure replacements (Exh. NG-NS-1, at 11). Thus, National Grid argues that it is necessary to terminate Boston Gas' PBR plan and increase base distribution rates to recover the cost of providing service to customers and to adjust the ratemaking paradigm applicable to its operations in this case so that adequate cost recovery will be possible on a going forward basis (Exh. NG-NS-1, at 11).

Third, National Grid argues that Boston Gas' current PBR plan is inadequate to sustain utility operations over the term of the plan because the types of cost-reduction alternatives available to Boston Gas are not of sufficient magnitude to reduce the overall level of O&M expense or even to hold the level constant (Exh. DPU-1-2, at 4). Fourth, National Grid asserts that the existing PBR mechanism does not adequately remediate the lost revenues experienced as a result of efforts undertaken by customers to lower their energy bills through energy efficiency activities (Exh. DPU-1-2, at 5-6).

Finally, National Grid argues that its proposal to terminate Boston Gas' existing PBR plan and, instead, implement revenue decoupling is designed to achieve the policy goals of PBR, while also addressing policy goals that are beyond the limitations of the current PBR plan (Exh. DPU-1-2, at 1). Specifically, National Grid states that its proposal is designed to provide the incentives and support for it to: (1) contain costs through efficient operation; (2) pursue a replacement schedule for leak-prone mains and services that serves the interests of safety, reliability and other public-interest considerations; and (3) enable the aggressive implementation of demand-side resources and energy efficiency (Exh. DPU-1-2, at 1).

D. Analysis and Findings

Companies operating under a PBR are expected not to seek changes to base rates during the term of the plan outside of the annual PBR adjustment mechanism. See, e.g., D.P.U. 09-30, at 19; Bay State Gas Company, D.T.E. 07-89, at 16, citing Incentive

Regulation, D.P.U. 94-158, at 22 (1995).[7] While there are certain limited opportunities available to companies to change rates during the term of a PBR plan (i.e., where applicable, a formal mid-period review and the option to petition the Department for changes in tariffed rates in reaction to extraordinary economic conditions) neither option is before us in this proceeding. See Bay State Gas Company, D.T.E. 05-27, at 400 (2005); D.T.E. 03-40, at 497 & n.263; The Berkshire Gas Company, D.T.E. 01-56 at 10-11 (2002). Instead, National Grid seeks to terminate Boston Gas' PBR plan and establish new base rates for Boston Gas based on an updated cost of service and revenue requirement in conjunction with its request for approval of a decoupling mechanism.

In D.P.U. 07-50-A at 83, the Department stated that we would permit a company to voluntarily terminate a rate plan in order to implement decoupling.[8] In that proceeding, the Department determined that it was not appropriate to implement decoupling in a piecemeal fashion by permitting distribution companies to layer decoupling proposals on top of existing rates. D.P.U. 07-50-A at 81-82. Therefore, we concluded that, when a company files a proposal for a revenue decoupling mechanism, it should do so in conjunction with the filing of a base rate proceeding. D.P.U. 07-50-A at 81. The purpose of this requirement is to ensure

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7 PBR mechanisms also may include adjustments for exogenous factors and earning sharing mechanisms. See, e.g., Bay State Gas Company, D.T.E. 05-27, at 360; D.T.E. 03-40, at 490-492, 500-502.

8 A notable exception to this provision is a distribution company operating under a PBR plan that resulted from a settlement. In such cases, the distribution company must obtain the agreement of all signatories to the settlement before the plan can be terminated. D.P.U. 07-50-A at 83; see also New England Gas Company, D.P.U. 08-35, Interlocutory Order on Scope of Proceeding and Request of the Attorney General and New England Gas Company to Bifurcate at 6-10 (August 20, 2008).

that rates will be set for decoupling purposes based on an understanding of the company's underlying distribution revenue requirement and an allocation of this revenue requirement among customer classes through an allocated cost of service study. D.P.U. 07-50-A at 81.

Because the PBR plan established in D.T.E. 03-40 was the result of a fully litigated case, National Grid may seek the termination of the PBR plan without the assent of any other party to that proceeding. D.P.U. 07-50-A at 83. Accordingly, pursuant to the Department's decoupling precedent, we will permit Boston Gas to file a rate case prior to the expiration of its PBR plan in conjunction with its proposal to implement decoupling.

In allowing a company to voluntarily terminate a rate plan to implement decoupling, a company is required to present a new ratemaking proposal for the Department's consideration. As always, such proposal must be "fully supported, and the distribution company will have the burden of proof to demonstrate the reasonableness of its proposal." D.P.U. 07-50-A at 50. The Department did not, however, foreclose the possibility of implementing decoupling in conjunction with a PBR plan. D.P.U. 07-50-A at 49-50. The Department noted that:

> [W]e will consider company-specific ratemaking proposals that account for: (1) the impact of capital spending on a company's required revenue target; and (2) the inflationary pressures with respect to the prices of goods and services used by distribution companies. We recognize that circumstances will vary from company to company and, as such, we will permit a certain amount of flexibility when establishing a revenue requirement for a distribution company. Such ratemaking proposals could be similar in structure to the PBR rate plans that most electric and gas companies have in place today.

D.P.U. 07-50-A at 50.

The proceedings in D.P.U. 09-30 marked the first instance in which a regulated utility operating under a PBR plan in Massachusetts sought to establish new rates during the term of the rate plan by filing for a general rate increase based on an updated cost of service and revenue requirement. D.P.U. 09-30, at 20. In that proceeding, Bay State Gas Company ("Bay State") sought to implement decoupling and continue its existing PBR plan but with a new set of cast-off rates. D.P.U. 09-30, at 5. In rejecting the continuation of Bay State's PBR plan, the Department concluded that the establishment of new rates based on a new test year of costs and revenues would completely change the dynamic of Bay State's rate plan and, in particular, a fundamental and significant component of the plan: the expected level of base rates that customers will pay over the term of the rate plan. D.P.U. 09-30, at 22-23. The fundamental theory underlying PBR is that it establishes a set of financial incentives that are designed to better encourage utilities to improve efficiency over time than would otherwise occur under traditional cost of service/rate of return ratemaking. D.P.U. 09-30, at 23. The Department concluded that the establishment of a new level of PBR-based rates based on an updated test year of costs and revenues runs contrary to these principles and changes the economic incentives to pursue medium and long-term planning and business decision making. D.P.U. 09-30, at 23, citing D.T.E. 05-27, at 399. We also concluded that the components of Bay State's PBR plan, including its price-cap formula, were integrally related and, as such, are dependent upon each other to balance the benefits between shareholders and ratepayers. D.P.U. 09-30, at 23. An interim change in rates, such as those based on an updated test year of costs and revenues, alters this balance. D.P.U. 09-30, at 23. Based on those considerations, the Department concluded that the establishment of new base rates required the termination of Bay State's PBR plan. D.P.U. 09-30, at 23.

In the instant proceeding, National Grid seeks to terminate Boston Gas' PBR plan coincident with the implementation of revenue decoupling. The Attorney General argues that National Grid should not be permitted to terminate Boston Gas' PBR plan because the plan is currently working as designed and would result in harm to customers (Attorney General Brief at 20; Attorney General Reply Brief at 4-5).

Consistent with our findings in D.P.U. 09-30, because the cast-off rates established in 2003 for Boston Gas will change as a result of this proceeding, the Department finds that it is appropriate to terminate Boston Gas' PBR plan. The components of Boston Gas' PBR plan, including its price-cap formula, are integrally related and, as such, dependent upon each other to balance the benefits between shareholders and ratepayers. A change in rates based on an updated test year of costs and revenues alters this balance.

Accordingly, for the reasons discussed above, we approve National Grid's request to terminate Boston Gas' current PBR plan. The earnings sharing mechanism, exogenous cost recovery mechanism, and the PBR rate adjustment formula that were part of the ten-year PBR plan also are terminated.

IV. REVENUE DECOUPLING MECHANISM PROPOSAL

A. Introduction

In Investigation Into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50 (2007), the Department investigated the use of revenue decoupling mechanisms as a means to better align gas and electric distribution companies' financial interests with policy objectives regarding the deployment of demand resources,[9] while ensuring that the companies are not financially harmed by increased use of demand resources. D.P.U. 07-50, at 1, 11. Decoupling mechanisms sever the link between a company's revenues and sales through a periodic reconciliation of the actual revenue that a company bills to its ratepayers with a specified target revenue level. D.P.U. 09-39, at 7. In this proceeding, National Grid proposes a full revenue decoupling approach for Boston Gas-Colonial Gas and Essex Gas (Exhs. NG-SFT-1, at 30-36; NG-AEL-4, at 53-54). Under a full decoupling approach, the mechanism makes no adjustments to allowed revenues for changes in sales from the effects of weather, economic factors, adoption of energy efficiency, or other influences (Exh. NG-SFT-1, at 34; Tr. 2, at 134).[10]

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9 Demand resources are installed equipment, measures, or programs that reduce end-use demand for electricity or natural gas. Such measures include, but are not limited to, energy efficiency, demand response, and distributed resources. D.P.U. 07-50, at 1 n.1.

10 In D.P.U. 07-50-A, the Department considered two types of decoupling mechanisms: (1) a full decoupling mechanism, under which a company would use its actual revenue collected from ratepayers to reconcile against the target revenue level; and (2) a partial decoupling mechanism, under which a company would adjust its actual revenue to take into account the effect of factors such as weather and the economy. The Department concluded that, in principle, both types of decoupling mechanisms would remove the financial disincentive that distribution companies currently face regarding the deployment of demand resources because, under both approaches, companies' revenue would be decoupled from a reduction in sales that result from such deployment. D.P.U. 07-50-A at 30-31. However, the Department concluded that the administrative burden, complexity, and potential for manipulation and error inherent in implementing a partial decoupling approach outweigh its advantages, relative to full decoupling. D.P.U. 07-50-A at 30-31.

The core elements of National Grid's proposed revenue decoupling mechanism are similar to the core elements approved for Bay State Gas Company ("Bay State") in D.P.U. 09-39 with the exception of National Grid's proposed treatment of residential non-heating to heating conversions, and the size of its proposed rate adjustment cap (Exh. NG-SFT-1, at 35-36). The components of the Companies' proposed revenue decoupling mechanism are described below. The Attorney General and other intervenors recommend certain modifications to National Grid's proposed revenue decoupling proposal (see, e.g., Attorney General Brief at 22).

B. National Grid's Proposal

1. Introduction

National Grid's revenue decoupling proposal calls for the Companies to adjust, on a semi-annual basis,[11] the rates for firm gas sales and firm transportation service in order to reconcile actual base distribution revenues with the benchmark base distribution revenues established in this proceeding using a revenue-per-customer approach (Exh. NG-SFT-1, at 31). National Grid proposes to implement the semi-annual revenue decoupling adjustments through its local distribution adjustment factor ("LDAF") and, accordingly, proposes certain amendments to its local distribution adjustment clause ("LDAC") tariff (Exh. NG-AEL-4, at 35-36).

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[11] The semi-annual adjustments are for the peak period covering November 1st through April 30th and the off-peak period covering May 1st through October 31st (Exh. NG-AEL-1, at 24-25).

2. Benchmark Revenue-Per-Customer

Consistent with the model approved for Bay State in D.P.U. 09-30, at 88-91, National Grid proposes to adopt a revenue-per-customer approach to revenue decoupling (Exhs. NG-SFT-1, at 31; DPU-1-24). In a revenue-per-customer approach, a company determines a benchmark amount or target revenue-per-customer for each of its rate classes in a base rate proceeding and the revenues it collects will vary based on the number of customers it serves See D.P.U. 07-50-A at 48-49, 85; D.P.U. 07-50, at 13-14.

National Grid proposes to establish target revenues and rate-year number of customers for: (1) Boston Gas-Essex Gas customers; and (2) Colonial Gas customers (Exhs. NG-SFT-1, at 31; DPU-1-20). These customers will be divided into three customer class groups: (1) residential heating customers (Residential Heating R-3 and Low-Income Residential Heating R-4);[12] (2) residential non-heating customers (Residential Non-Heating R-1 and Low-Income Residential Non-Heating R-2); and (3) commercial and industrial ("C&I") customers (G-41, G-42, G-43, G-44, G-51, G-52, G-53 and G-54) (Exhs. NG-SFT-1, at 36-37; NG-AEL-4, at 41).[13] National Grid proposes to exclude from the revenue decoupling

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12 National Grid proposes to include non-discounted revenues associated with low-income customers for the purpose of establishing the target revenue-per-customer (which incorporates both regular and low-income heating customers), billed revenue-per-customer, and the decoupling adjustment for residential heating customers (Exhs. NG-SFT-1, at 38; DPU-1-29).

13 National Grid's proposal to include all C&I customers in one customer class group is intended to address the large variation in the number of customers per rate class (Exh. NG-SFT-1, at 37). Some C&I rate classifications have few customers (e.g., G-52 and G-53) and, therefore, including all C&I customers in one group avoids potentially

mechanism street lighting customers (G-07 and G-17), interruptible customers, and special contract customers because these customers operate under contract terms or other circumstances that it states are inherently different from the Companies' other C&I customers (Exhs. NG-SFT-1, at 37; DPU-1-27).[14] The target revenue-per-customer for each customer class group will remain the same until new rates are authorized by the Department (Exh. NG-SFT-1, at 34).

3. Revenue Decoupling Adjustments

As noted above, National Grid proposes that the revenue decoupling adjustment be made through the LDAF (Exhs. NG-SFT-1, at 33-34; NG-AEL-4, at 42-43).[15] Consistent with the method approved in D.P.U. 09-30, at 88-90, under the Companies' proposal rates will be

volatile decoupling reconciliations for the remaining customers in these rate classes in the event that other customers stop taking service (Exh. NG-SFT-1, at 37-38).

14 National Grid states that it does not meter the gas use of its street lighting customers, as they operate under a tariff that charges customers on a per-fixture basis (Exh. DPU-1-27). National Grid notes that the Companies receive the same revenue-per-customer for this class irrespective of the amount of natural gas consumed and, therefore, it is not necessary to include these customers in the revenue decoupling mechanism (Exh. DPU-1-27). Regarding special contract customers, the Companies state that they are transportation-only customers that are not assessed an energy efficiency surcharge, making them ineligible to participate in the Companies' energy efficiency programs (Exh. DPU-1-27). Similarly, National Grid states that the Companies' few interruptible customers do not pay the energy efficiency surcharge and, therefore, cannot participate in energy efficiency programs sponsored by National Grid (Exh. DPU-1-27).

15 For Bay State, the revenue decoupling adjustments do not occur via the LDAC; rather, the Department approved a separate revenue decoupling adjustment factor and tariff. See D.P.U. 09-30, at 25, 33, 117.

adjusted at the start of the peak season and at the start of the off-peak season (Exh. NG-AEL-1, at 24-25).[16]

The proposed revenue decoupling adjustment is the sum of the adjustments calculated for each of the three customer class groups plus a reconciliation component (discussed in Section IV.A.5, below) (Exh. NG-AEL-4, at 35-36).[17] More specifically, the revenue decoupling adjustment for the peak or off-peak period is calculated as follows. First, National Grid will calculate the difference between the actual billed revenue-per-customer and the benchmark base revenue-per-customer for the three customer class groups for the recently completed peak or off-peak period (Exhs. NG-SFT-1, at 33; NG-AEL-1, at 24; NG-AEL-4, at 53-54).[18] The difference for each customer class group is multiplied by the average number of existing customers billed in that season and for that group (Exhs. NG-SFT-1, at 33-34; NG-AEL-4, at 53-54). Next, the sum of the resulting differences in revenues for the three customer class groups is added to the revenue decoupling reconciliation (Exhs. NG-SFT-1, at 34; NG-AEL-4, at 53-54). The resulting total is then divided by the forecast throughput volume, inclusive of all firm sales and firm transportation throughput, for the upcoming peak

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16 Peak-period and off-peak period revenue decoupling adjustments will be effective each year on November 1 and May 1, respectively (Exh. NG-AEL-1, at 24-25).

17 The revenue decoupling adjustment formula is specified in section 6.17 of the proposed LDAC tariff (Exh. NG-AEL-4, at 53-54).

18 For the first rate year, National Grid proposes to track, starting on November 2, 2010, for each of the three customer groups: (1) actual billed revenues in each of the two seasons; and (2) the average number of existing customers in each customer class group (Exh. NG-SFT-1, at 32). Dividing the billed revenues by customer count will produce the actual revenue-per-customer for each customer class group for each season (Exhs. NG-SFT-1, at 32-33; NG-AEL-4, at 40).

or off-peak period to arrive at the applicable revenue decoupling adjustment unit charges (Exhs. NG-SFT-1, at 33; NG-AEL-4, at 53-54).

The proposed LDAC tariff provisions provide that the revenue decoupling adjustment will be applied to customer bills in the next corresponding season (i.e., the revenue decoupling adjustment for the peak period will be applied to customer bills in the next peak period and the revenue decoupling adjustment for the off-peak period will be applied to customer bills in the next off-peak period) (Exh. NG-AEL-4, at 36).

National Grid proposes to make its first revenue decoupling adjustment filing on September 15, 2011 to adjust revenues from the preceding peak season (i.e., November 2010 through April 2011) (Exhs. NG-SFT-1, at 32; NG-AEL-1, at 25). National Grid proposes to make this revenue decoupling adjustment filing in conjunction with its 2010 through 2011 peak gas cost reconciliation filing (Exh. NG-AEL-1, at 25).

4. Revenue Cap

Under the Companies' proposal, the total peak or off-peak revenue decoupling rate adjustment may not exceed one percent of total revenues from firm sales and transportation throughput for the most recent corresponding peak or off-peak periods, with transportation revenues to be adjusted by imputing the Companies' cost of gas charges for that period (Exh. NG-AEL-4, at 36).[19] To the extent that the application of the revenue cap results in a revenue

[19] In D.P.U 09-30, at 116, the Department approved a three percent revenue cap for Bay State. In determining the appropriate level of cap on the total amount of revenue decoupling adjustments, the Department struck a balance between its stated goal of promoting all cost-effective demand resources and its rate structure goals, including rate continuity. See D.P.U. 07-50-A at 23-24; D.T.E. 05-27, at 305; D.T.E. 02-

decoupling rate adjustment that does not fully recover the calculated decoupling adjustment, the difference will be deferred and included in the decoupling reconciliation for recovery in the subsequent year during the corresponding peak or off-peak period (Exhs. NG-AEL-4, at 36; DPU-1-22).

5. Revenue Decoupling Reconciliation Adjustment

The total revenue decoupling adjustment will be trued-up for variances between actual and projected sales (Exh. NG-AEL-4, at 53-54). To accomplish this true-up, a revenue decoupling reconciliation adjustment will be calculated separately for each season and will be reflected in the revenue decoupling adjustment for the corresponding season in the following year (Exh. NG-AEL-4, at 53-54).

The Companies will track for Boston Gas-Essex Gas and Colonial Gas, in separate peak and off-peak accounts, the accumulated revenues toward the revenue decoupling adjustment, as calculated by multiplying the revenue decoupling adjustment by the corresponding seasonal firm sales and transportation throughput and the revenue decoupling adjustment allowed revenues (Exh. NG-AEL-4, at 53-54).[20] The Companies propose to apply carrying costs to the

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24/25, at 252 (2002); D.P.U. 88-67, at 201. The Department approved a three percent cap, based on total concurrent peak or off-peak actual base distribution and gas commodity revenues as the maximum amount of base distribution revenue decoupling adjustments for the upcoming peak or off-peak period. D.P.U. 09-30, at 116. The Department found that this level of cap struck a reasonable and appropriate balance between the above-noted ratemaking goals. D.P.U. 09-30, at 116.

20 To determine an amount of revenues to be reconciled in the following year, for each customer class group and for each season, actual billed revenue-per-customer is subtracted from target revenue for each customer class group (Exh. NG-SFT-1, at 33). If the amount is negative (i.e., actual revenue-per-customer exceeds target revenue-per-

average monthly balance of the decoupling reconciliation adjustment at the prime lending rate (Exh. NG-AEL-4, at 36).

6. Treatment of New Customers

National Grid proposes to treat customer counts and revenues associated with new customers (i.e., new customer meters) outside of the revenue decoupling mechanism (Exhs. NG-SFT-1, at 41; NG-AEL-4, at 53-54).[21] Specifically, National Grid proposes that, between the time new rates go into effect and the time rates are changed by the Department, customer counts and customer revenues associated with new customers will be excluded from the calculation of the revenue decoupling adjustment (Exh. NG-SFT-1, at 41). In this way, National Grid will be able to retain the additional revenue generated from those new customers. National Grid proposes to blend the revenues from new customers into the customer class groups at the time of the Companies' next base rate case (Exhs. NG-SFT-1, at 41; DPU-1-21). Under National Grid's proposal, the revenue decoupling adjustment will be charged or credited to these new customers through the LDAF, in the same manner as for existing customers (Exh. NG-SFT-1, at 41-42).

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customer) then a credit will be given to customers; if the amount is positive, then a surcharge will be levied on customers (Exh. NG-SFT-1, at 33). The revenue-per-customer amount (either positive or negative for each customer class group for each season) is multiplied by the average number of existing customers billed in that season and for that group (Exh. NG-SFT-1, at 33).

[21] In D.P.U. 09-30, at 98, the Department approved Bay State's proposal to delay the inclusion in the revenue decoupling mechanism of the new large and extra-large C&I customers until the company's next base rate case.

7. Treatment of Non-Heating to Heating Conversions

National Grid proposes that it be allowed to retain the incremental revenues generated by existing customers converting from non-heating to heating service (Exh. NG-SFT-1, at 35 n.37).[22] Specifically, the Companies would include a residential non-heating customer in the residential non-heating customer class for the months that the customer is a non-heating customer and then, after conversion, include that customer in the residential heating customer class for the months that the customer is a heating customer (Exh. NG-SFT-1, at 35, 38-39). Accordingly, unlike Bay State, National Grid's proposed revenue decoupling adjustment does not include a credit for the difference between the residential non-heating and residential heating benchmark base revenue-per-customer for any existing residential non-heating customer that converts to heating service and that does not require any incremental capital investment for the conversion (Exh. NG-SFT-1, at 35 n.37).

C. Positions of the Parties

1. Attorney General

The Attorney General submits that National Grid has failed to show that, without its proposed revenue decoupling mechanism, it would be unable to retain a reasonable amount of revenues to operate its system, ratepayers would be unable to engage in energy efficiency efforts, or that the Companies would be unable to provide safe and reliable operations

[22] In D.P.U. 09-30, at 103, the Department directed Bay State Gas Company to provide a credit to customers in its calculations of the revenue decoupling adjustments for the difference between the residential non-heating and residential heating benchmark base revenue-per-customer for any existing residential non-heating customer who converts to heating service and that does not necessitate any incremental capital investment on the part of the company for the conversion.

(Attorney General Brief at 29, citing Tr. 2, at 150, 152-153). The Attorney General disputes the Companies' presumption that the proposed revenue decoupling mechanism will automatically lead to operating efficiencies (Attorney General Brief at 22-23). Instead, the Attorney General argues that, because it is a perfect guarantee of revenue recovery, the revenue decoupling mechanism creates a disincentive for National Grid to contain costs (Attorney General Brief at 23, citing Exh. AG-DED-1, at 23).

In addition, the Attorney General contends that the proposed revenue decoupling mechanism does not guarantee savings for ratepayers (Attorney General Brief at 23). According to the Attorney General, savings will be restricted to customers participating in energy efficiency programs and these savings will exist only as long as base distribution rates and other non-bypassable charges are smaller in share than commodity related charges (Attorney General Brief at 23, citing Exh. AG-DED-1, at 23). The Attorney General also takes issue with the studies offered by National Grid to demonstrate savings and asserts that evidence from other jurisdictions where decoupling is in place raises concerns about revenue over-compensation (Attorney General Brief at 24-28, citing Exh. AG-DED-1, at 26, 27, 28, 32).

The Attorney General argues that, if the Department accepts National Grid's proposed revenue decoupling mechanism, it should make certain modifications to the proposal (Attorney General Brief at 22). Specifically, the Attorney General argues that the Department should reject the Companies' proposal to include in its monthly customer count, non-heating customers who convert to heating (Attorney General Brief at 30). The Attorney General contends that the Companies have not provided any information, as required by precedent, to support the need to retain revenues generated by such conversions in order to cover any costs associated with these conversions (Attorney General Brief at 30, citing Tr. 17, at 2240-2241; D.P.U. 09-39). As such, the Attorney General recommends that the Companies be required to credit to ratepayers any revenues generated by such conversions (Attorney General Brief at 30).

In addition, the Attorney General argues that if the Companies' proposed revenue decoupling mechanism is approved, the Department should not permit the Companies to include the incremental costs associated with the addition of new customers in the costs of service used to set rates in this case (Attorney General Brief at 30-31). According to the Attorney General, the Companies improperly propose to include operations and maintenance ("O&M") expenses associated with new customers in cost of service (Attorney General Brief at 31-32, citing Exhs. AG-33-33; AG-33-35; AG-33-36).[23] The Attorney General asserts that if the Companies keep all of the revenues from the addition of these new customers, so too should they bear the costs of those customers (Attorney General Brief at 33). As such, the Attorney General urges the Department to reduce the Companies' revenue requirements to reflect the elimination of the incremental costs associated with the addition of new customers (Attorney General Brief at 33).

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23 In particular, the Attorney General notes that National Grid has included in the costs of service, the costs of free boiler programs, customer incentives for conversions and added usage, and sales commissions (Attorney General Brief at 31-32, citing Exhs. AG-33-33, AG-33-35, AG-33-36).

Further, the Attorney General argues that implementation of the revenue decoupling mechanism will result in a significant reduction in the Companies' risk, which should be reflected in its return on equity ("ROE") (Attorney General Brief at 23). Finally, the Attorney General argues that the Department should conduct an evaluation of the Companies' revenue decoupling plan after a three-year period (Attorney General Brief at 29).[24] The Attorney General contends that such a review is necessary given that the Companies have not presented any evidence that the proposed mechanism will result in increased energy efficiency program investments, accomplish the goals the Department has set in other proceedings, increase energy efficiency, and avoid shifting risk onto ratepayers (Attorney General Brief at 29, citing Tr. 2, at 140, 141-142, 150-151, 163-164).

2. DOER

DOER argues that the Department should approve the Companies' proposed method for determining target and actual revenues per customer and reconciling differences (DOER Brief at 4). As the proposed revenue decoupling mechanism fully decouples sales from revenues, DOER argues that it achieves the Department's objective of removing a principal obstacle to the adoption of cost-effective energy efficiency and demand response programs (DOER Brief at 4).

DOER notes that the proposed revenue decoupling mechanism differs from the mechanism approved in D.P.U. 09-30 in the treatment of incremental revenues received from

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24 The Attorney General suggests that the review could run concurrently with, or as part of, the Department's three-year review of the Companies' energy efficiency program performance (Attorney General Brief at 29, citing Exh. AG-DED-1, at 29).

existing residential non-heating customers who convert to heating (DOER Brief at 4). DOER argues that the Department should reject the Companies' proposal to retain these incremental revenues (DOER Brief at 4). According to DOER, allowing the Companies to retain these revenues would transform the revenue decoupling mechanism from full decoupling to partial decoupling which would operate in one direction with respect to residential upgrades (i.e., to increase the revenues received by the Companies) (DOER Brief at 5). DOER contends that there is no justification for retaining the revenues from residential conversions, particularly when revenues from C&I customers are reconciled and the benefits of converting for both residential and C&I customers are similar (DOER Brief at 5-6). DOER disputes National Grid's argument that retaining these incremental revenues provides an incentive to convert residential customers from non-heating to heating service (DOER Brief at 6). DOER argues that if there are benefits associated with these conversions and the Companies are recovering the marketing expenses associated with these upgrades (by inclusion of those expenses in the test year), then the Companies should have more than an adequate incentive to continue to market upgrades to their existing customers (DOER Brief at 6). Thus, DOER asserts that, consistent with the directives in D.P.U. 09-30, at 102, the Department should require the Companies to credit back to customers the incremental revenues associated with residential conversions (DOER Brief at 6-7).

3. Environment Northeast

ENE argues that the Companies' proposed decoupling mechanism closely tracks the mechanism approved by the Department for Bay State in D.P.U. 09-30 (ENE Brief at 6).

ENE recommends approval of the Companies' decoupling proposal because, as a full decoupling mechanism, it will separate revenues from all changes in consumption, regardless of the underlying cause of the changes and, therefore, is consistent with Department precedent and the Commonwealth's policy goals (ENE Brief at 8, citing D.P.U. 07-50; D.P.U. 09-30).

ENE asserts, however, that the Department should include all new customers in the decoupling mechanism and should not allow the Companies to retain the revenues associated with adding new customers, as proposed (ENE Brief at 8-9; ENE Reply Brief at 2-3). If approved as proposed, ENE contends that the revenue decoupling mechanism will not separate revenues from sales for new customers (ENE Brief at 9). According to ENE, such a result will allow the Companies to collect full revenues for these new customers and preserve an incentive to maximize sales for these customers, defeating the very purpose of decoupling (ENE Brief at 9). As such, ENE urges the Department to modify the Companies' decoupling proposal so that new customers are included in the semi-annual reconciliations on the same basis as all other customers (ENE Brief at 9; ENE Reply Brief at 3).

Further, ENE asserts that the Department should ensure that all customers, including all new customers, are part of the reconciliation process and thus are fully incorporated into the decoupling mechanism at the time service begins (ENE Brief at 9; ENE Reply Brief at 3). ENE argues that exempting a subset of customers from the decoupling mechanism would not only threaten the integrity of National Grid's decoupling mechanism but also create a complicated administrative process that creates two customer categories: customers whose participation in the decoupling mechanism benefits and promotes all cost-effective energy efficiency and a second group of customers for whom the Companies have an incentive to maximize sales (ENE Brief at 9-10).[25]

Accordingly, ENE recommends that the Department modify the Companies' proposed revenue decoupling mechanism so that new customers are included in the semi-annual reconciliation on the same basis as all other customers (ENE Reply Brief at 3). ENE states that because the Department requires the total reconciliation amount to be recovered from or returned to all customers uniformly across all rate classes, the Department should ensure that all new customers are part of the reconciliation process and, thus, are fully incorporated into the decoupling mechanism at the time they start service (ENE Reply Brief at 3 & n.7, citing D.P.U. 07-50-A at 55).

Alternatively, ENE argues that, if it is ultimately determined that new customers should be excluded from the decoupling mechanism until the next rate proceeding, at a minimum the Department should require the Companies to track the usage of new customers as compared to existing customers in each particular rate class, as well as the cost to connect new customers by rate class (ENE Reply Brief at 2 n.4, citing D.P.U. 09-30, at 100-101).

4. National Grid

National Grid states that its proposed revenue decoupling mechanism is fully consistent with the Department's policy goals and is similar in design to the mechanism approved by the Department for Bay State in D.P.U. 09-30, with differences limited to those aspects of the

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25 ENE also notes that the revenue-per-customer model is designed to accommodate the costs of adding new customers to the system and, therefore, the exclusion of new customers is duplicative and unnecessary (ENE Brief at 10).

mechanism requiring refinement to address specific circumstances of the Companies' system (Exh. NG-SFT-1, at 6). In addition, National Grid argues that its approach to decoupling fully supports its customers' interests in energy efficiency, the Commonwealth's interests in reducing the environmental impacts associated with energy use, and the Companies' interests in a sustainable ratemaking model for their natural gas delivery system (Exh. NG-SFT-1, at 6-7). According to National Grid, the Companies' proposed revenue-per-customer model is appropriately structured to promote the efficient deployment of energy efficiency and demand resources, as contemplated by D.P.U. 07-50-A at 82 (Exh. NG-SFT-1, at 6-7).

National Grid argues that its proposed one percent revenue reconciliation cap is consistent with the Department's directive in D.P.U. 07-50 that a proposed revenue decoupling mechanism "be consistent with Department precedent related to rate continuity, fairness, and earnings stability" (Exh. DPU 1-26, citing D.P.U. 07-50). According to National Grid, the Companies' proposed cap is similar to the cap approved by the Department for Bay State as part of that company's revenue decoupling mechanism, where a cap set at three percent of total revenues (i.e., both distribution and gas commodity revenues) was adopted (Exh. DPU 1-26, citing D.P.U. 09-30, at 114-116). The Companies state that, in addition to a three percent cap on the revenue decoupling mechanism, the Department approved a one percent cap on Bay State's TIRF for a total cap of four percent for both mechanisms (Exh. DPU 1-26, citing D.P.U. 09-30, at 130, 134). Therefore, in line with the total revenue cap approved for Bay State (i.e., one percent TIRF and three percent revenue decoupling mechanism), National Grid states that it proposed a one percent cap for its decoupling mechanism and a three percent cap for its TIRF (Exh. DPU 1-26). Keeping the total cap for both mechanisms the same, National Grid argues that it is appropriate to switch the percentage caps for its proposed decoupling mechanism and its proposed TIRF in recognition of the substantial infrastructure needs on the Companies' system (Exh. DPU-1-26).

Regarding the treatment of new customers (i.e., where the Companies add a new meter and associated service), National Grid argues that Department precedent provides that such customers should be excluded from the revenue decoupling mechanism as a matter of ratemaking policy (National Grid Brief at III.6, citing D.P.U. 09-30, at 94-95, 100; National Grid Reply Brief at 16). National Grid submits that in D.P.U. 09-30, at 94, 97, the Department determined that a company should calculate the seasonal revenue decoupling adjustment using the actual number of customers, excluding all new customers, as this is consistent with the Department's existing ratemaking principles which allow gas companies to retain incremental revenues from new customers added after the test year as an incentive to add and serve new customers and reduce the average cost of distribution service for all customers over the long-term (National Grid Brief at III.7; National Grid Reply Brief at 19-21).

Further, National Grid argues that it should be allowed to retain all incremental revenue associated with serving new customers until rates are established in the Companies' next rate case, whereupon the benefits will be shared with customers through a reduction in the average cost of service (National Grid Brief at III.4, citing Exh. NG-SFT-1, at 35; National Grid Reply Brief at 18, 22, citing D.P.U. 09-30, at 94). In this regard, National Grid claims that ENE's position that revenues obtained through new customer growth should be flowed back to customers is inconsistent with Department precedent and would act to eliminate the Companies' incentive to pursue beneficial system load growth and, therefore, would deprive existing customers of the benefits of reductions in the Companies' average cost of distribution service (National Grid Reply Brief at 17, 19-21).

Regarding the treatment of existing residential customers who convert from non-heating to heating, National Grid argues that the Department should include residential conversion customers in the revenue decoupling mechanism and allow the Companies to retain the incremental revenues associated with such conversions (National Grid Brief at III.7-8). National Grid argues that the Department's longstanding policy in favor of promoting the addition of new customers so long as it lowers average costs over time extends to existing residential customers who convert from non-heating service to heating service (National Grid Brief at III.7-8, citing D.T.E. 03-40, at 248-249; RR-AG-44). National Grid contends that growth from residential conversions has benefitted the Companies' distribution customers (National Grid Brief at III.7-8, citing D.T.E. 03-40, at 248-249; RR-AG-44). Specifically, National Grid asserts that growth associated with customer conversions has added significant throughput and there is significant potential for customer migration to occur on its system (National Grid Brief at III.10; see, also, Exh. NG-SFT-1 at 35, n. 37). Therefore, National Grid argues that it is important to maintain the incentive to promote residential conversions because the rates of return associated with these customers will provide substantial benefits to all customers in setting rates in the future (National Grid Brief at III.10; National Grid Reply Brief at 24-25). National Grid argues that, consistent with this policy favoring system growth and, in light of the significant potential in the Companies' systems for residential non-heating to heating conversions, the Department should include residential conversion customers in the revenue decoupling mechanism and allow the Companies to retain any incremental revenues (National Grid Brief at III.8, citing Exh. NG-SFT-1, at 35; National Grid Reply Brief at 16).

Further, National Grid argues that it is appropriate to retain the incremental revenues associated with non-heating to heating conversions regardless of whether the Companies have incurred capital costs for the conversion (National Grid Brief at III.8). National Grid claims that this approach is consistent with the Department's existing ratemaking principles because the Companies are currently allowed to retain the incremental revenues associated with converting all residential non-heating to heating customers between rate cases (National Grid Brief at III.8). Also, National Grid argues that, whereas Bay State did not oppose providing a credit to customers through the revenue decoupling mechanism for any incremental revenues associated with customers conversions where no capital contribution was required, its own situation is different (National Grid Brief at III.10, citing D.P.U. 09-30, at 101-102; National Grid Reply Brief at 23-24). National Grid contends that differentiating customers who require a capital contribution to accommodate heating service for purposes of the decoupling reconciliation would require a change to its billing system and significant effort to implement because of the large number of customer conversions each year (National Grid Brief at III.12). National Grid submits that although the Companies would support retaining the revenues for C&I customers whose load increases with the addition of new services, the Companies have not proposed to retain this incremental revenue because of the difficulties involved in tracking added load resulting from new services versus added load resulting from increased usage under existing services (National Grid Brief at III.12).

National Grid notes that the Department's finding in D.P.U. 09-30, at 102 that it was reasonable to require a credit for incremental revenues from residential customer conversions where no capital investment on the part of the company was required was based, in part, on the equity of the fact that the design of the decoupling mechanism insulated the company from the potential revenue loss from large C&I customers' switching to smaller rate classes (National Grid Brief at III.10-11). However, the Companies argue that any incremental revenue associated with existing C&I customers is fully factored into the revenue decoupling reconciliation to the benefit of customers and not to the benefit of the Companies (National Grid Brief at III.11). Further, National Grid notes the loss of an existing C&I customer will result in lower revenue for the Companies (National Grid Brief at III.11).

In addition, National Grid offers several arguments to counter the Attorney General's position that if the Department accepts the Companies' proposal to retain the incremental revenues associated with residential non-heating to heating conversions, it should remove incremental costs associated with the addition of new customers from the cost of service used to set rates in this proceeding (National Grid Brief at III.13, citing Attorney General Brief at 31-33; National Grid Reply Brief at 16). First, National Grid argues that the Attorney General's recommendation explicitly recognizes that customers converting from non-heating service to heating service are, for all intents and purposes, new customers (National Grid Brief at III.13). National Grid claims that the Department has already found that inclusion of new customers should be delayed until the next base-rate proceeding because: (1) there may be capital costs that have to be incurred to acquire the customer; and (2) ratemaking principles are structured to provide an incentive to a gas company to add customers where the effect is to lower the average cost of distribution service (National Grid Brief at III.13, citing RR-AG-44; D.P.U. 09-30, at 94-95, 98-99, 100). National Grid argues that residential customers' converting from non-heating to heating service provides a net benefit to the system in terms of the costs to add the customer and the revenues produced over the customer's lifetime, which have the effect of reducing fixed costs for all customers (National Grid Brief at III.13-14).

Next, National Grid contends that a portion of the marketing costs cited by the Attorney General and recommended for disallowance on the basis of the migrating residential customer issue pertains to activities that the Companies undertake in relation to C&I load and bears no relation to the conversion of residential non-heating customers to heating customers (National Grid Brief at III.14).

National Grid also argues that the Companies are not allowed to keep the incremental revenue associated with these and all other new customers in perpetuity, which would have to be the case to justify exclusion of the marketing and promotional cost from the cost of service (National Grid Brief at III.14). National Grid argues that basic ratemaking principles require that the revenue associated with customers who are new to the system, and new to the residential heating class, are included in the Companies' billing determinants in the next rate case so that existing distribution customers receive the benefit of that growth (National Grid Brief at III.14, citing D.P.U. 09-30, at 94-95, 98-99, 100). According to the Companies, given that the marketing and promotion expense are needed to provide the impetus for new residential and C&I conversions to gas service, as well as residential upgrades, and given that customers are the ultimate beneficiaries of the contribution to fixed system costs that results from all types of customer additions produced by the expenditure of these costs, there is no basis for disallowing these costs from the cost of service (National Grid Brief at III.14).

D. Analysis and Findings

1. Introduction

The Department's authority to adopt decoupled rates arises from our delegated authority under G.L. c. 164, § 94 to prescribe the rates and prices that utilities may charge. D.P.U. 07-50-B at 2, citing Boston Edison Co. v. City of Boston, 390 Mass. 772, 774 (1984). In determining the propriety of such rates, the Massachusetts Supreme Judicial Court has affirmed that the Department must find that they are just and reasonable. See Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264 n.13 (2002). Therefore, in reviewing the Companies' proposed revenue decoupling mechanism, the Department must find (1) that their operation will result in rates that are just and reasonable; and (2) that their design is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B.

In D.P.U. 07-50-A at 24, the Department found that promoting the implementation of all cost-effective demand resources is a top priority. In order to realize the full potential of demand resources, we stated that it is essential to leverage the distribution companies' relationships with customers as well as with any other entities that will be engaged in the development and deployment of such demand resources. D.P.U. 07-50-A at 25. In considering the various ratemaking alternatives that would promote the implementation of all cost-effective demand resources, the Department concluded that a full decoupling mechanism best meets the 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. The Department noted that the conclusions reached in D.P.U. 07-50-A represented general statements of policy revenue decoupling and that issues such as the equity associated with and appropriateness of specific revenue recovery proposals will be addressed based on the evidence and argument presented in the adjudication of a distribution company's individual decoupling proposal. D.P.U. 07-50-B at 28-29.

As described above, the Companies propose to implement revenue decoupling using a full decoupling approach with a one percent revenue cap in any season (i.e., peak or off-peak) on the increase to rates from the operation of the revenue decoupling mechanism. The parties raise certain concerns relating to the Companies' (1) proposal to retain the revenues from customer growth, and (2) proposed treatment of non-heating to heating conversions in the proposed revenue decoupling mechanism. In addition, the Attorney General argues that the Department should conduct a formal evaluation of the Companies' revenue decoupling plan after a three-year period. Each of these issues is addressed below. The Department will address issues related to the impact of revenue decoupling on the Companies' ROE in Section XI.D.4, below.

2. Benchmark Revenue-Per-Customer and Revenue Decoupling Adjustments

National Grid proposes to implement a revenue decoupling mechanism using a revenue-per-customer approach (Exhs. NG-SFT-1, at 31; DPU-1-24). Under its proposal, all classes of Boston Gas-Essex Gas and Colonial Gas customers are divided into three groups: (1) non-heating residential; (2) heating residential; and (3) C&I (Exhs. NG-SFT-1, at 36-37; NG-AEL-4, at 41). For each customer class group, a peak and off-peak base revenue-per-customer benchmark will be calculated using the base distribution rates approved in this proceeding (Exh. NG-AEL-1, at 24-25). For the peak and off-peak period, the difference between the actual billed revenues per customer and the benchmark base revenues per customer for each customer class group will be multiplied by the actual average number of existing customers for that group (Exhs. NG-AEL-1, at 24-25; NG-AEL-4, at 53). The sum of the amounts calculated for the three customer class groups, along with the reconciliation component, will be the total revenue decoupling adjustment for that period (Exhs. NG-AEL-1, at 24-25; NG-AEL-4, at 53). This amount will be recovered in the upcoming corresponding season through a unit charge applicable to all customers (Exhs. NG-AEL-1, at 24-25; NG-AEL-4, at 53).

The Companies' proposed revenue-per-customer decoupling approach is consistent with the method endorsed by the Department in D.P.U. 07-50-A at 48-50. Accordingly, we accept the Companies' proposed revenue-per-customer approach as the framework for the Companies' revenue decoupling mechanism in this case. Further, we find that the Companies' proposal to calculate separate revenue decoupling adjustments for Boston Gas-Essex Gas and Colonial Gas is consistent with National Grid's proposed consolidation of rates for the Companies.

In D.P.U. 07-50-A at 55, the Department stated that each distribution company shall propose a base rate adjustment mechanism that reconciles target to actual revenues for each rate class. In D.P.U. 09-30, at 90, given the similar cost and load characteristics of the residential customer classes within the heating and non-heating rate classes, and for rate simplicity, the Department approved Bay State's proposal to establish one benchmark base revenue-per-customer that is applicable to the non-heating rate classes and another benchmark base revenue-per-customer that is applicable to the heating classes. For these same reasons, the Department approves National Grid's proposal to adopt one benchmark base revenue-per-customer for its residential heating and one for its residential non-heating customer class groups.

Similarly, in D.P.U. 09-30, at 90-91, the Department considered the potential migrations from one C&I rate class to another that could cause class-specific benchmark revenues per customer to be unrepresentative of the cost to serve that class, and accepted Bay State's proposal to aggregate its C&I rate classes into one group and develop one benchmark base revenue-per-customer for that group. For these same reasons, the Department approves National Grid's proposal to develop one benchmark base revenue-per-customer for its C&I customer class group (Exh. NG-SFT-1, at 37-38).

The Companies propose to implement peak-season and off-peak-season decoupling revenue adjustments in order to align the adjustments with the allocation of costs between peak and off-peak seasons and to set prices that are consistent with seasonality of use. Over- and under-recoveries of delivery revenues in the heating season would be reconciled in the following heating season, while over- or under-recoveries of off-peak season revenues would be reconciled in the following off-peak season (Exh. DPU-1-25). This approach is consistent with the Companies' existing method of reconciliations through its LDAC and its Cost of Gas Adjustment Clause ("CGAC") (Exh. NG-AEL-5, at 2-118). It is also consistent with the seasonal revenue decoupling adjustment approved for Bay State in D.P.U. 09-30, at 91. Accordingly, we approve the Companies' proposal to use peak and off-peak benchmark base revenue-per-customer in their decoupling revenue adjustments.

3. Revenue Cap

In order to limit rate impacts of revenue decoupling reconciliations on end-use customers, the Companies' proposed revenue decoupling mechanism includes a cap on the total amount of revenue that may be added to rates in any season, with the cap set at one percent of total revenues (i.e., combined distribution and gas commodity revenues) in any season. Any revenue amounts that exceed the cap would be deferred for reconciliation in the subsequent same season, with the deferred balance accruing with interest (Exh. DPU-1-26). National Grid correctly notes that, as part of a revenue decoupling mechanism, a revenue cap is intended to limit the volatility in end-use customer bills that could result from large changes in consumer use or customer numbers that might result from weather, economic, or other factors (Exh. DPU-1-26).

The Department finds that the application of a revenue cap is consistent with the Department's directive in D.P.U. 07-50, at 12 that a revenue decoupling mechanism must "be consistent with Department precedent related to rate continuity, fairness, and earnings stability." If a cap is not applied, large revenue decoupling adjustments could occur, thereby violating the Department's rate structure goal of rate continuity. See D.P.U. 09-39, at 85-86; D.P.U. 09-30, at 114; D.P.U. 08-35, at 221; Massachusetts Electric Company, D.P.U. 92-78, at 116 (1992); D.P.U. 88-67 (Phase I) at 201.

In determining the appropriate cap on the total amount of revenue decoupling adjustments, the Department must balance the goal of avoiding deferrals and its rate structure goals including rate continuity. D.P.U. 09-39, at 87; D.P.U. 09-30, at 116; see D.P.U. 07-50-A, at 24; D.T.E. 05-27, at 305; D.T.E. 02-24/25, at 252; D.P.U. 88-67, at 201. Revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates. D.P.U. 09-39, at 87.

In D.P.U. 09-39, at 87, and D.P.U. 09-30, at 116, we considered the same issue and balanced the same concerns. Ultimately, in each instance, the Department imposed a three percent cap on annual revenue decoupling adjustments. D.P.U. 09-39, at 87; D.P.U. 09-30, at 116-117. The same rationale applies here. We find that a three percent cap, based on total concurrent peak or off-peak actual base distribution and gas commodity revenues, representing the maximum amount of base distribution revenue decoupling adjustments for the upcoming peak or off-peak period, strikes an appropriate balance between avoiding deferrals and maintaining rate continuity.[26]

[26] In Section VI.D.3.b, below, the Department approves a cap of one percent of total revenues for the limit on TIRF revenue requirement associated with TIRF capital costs spent over the last year that may be included in rates each year.

Consistent with our findings in D.P.U. 09-39, at 87-88, and 09-30, at 116-117, any unrecovered revenue decoupling adjustment that is above this three percent cap shall be deferred for recovery in the next corresponding period, with carrying charges at the prime rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates. Because the revenue decoupling adjustments are reconciled from one season to another, the Department finds that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render a three percent revenue cap inappropriate. Accordingly, the Department will review, re-evaluate, and modify the revenue cap, as necessary, during the Companies' peak and off-peak revenue decoupling adjustment filings. D.P.U. 09-30, at 117. In its compliance filing to this Order, the Department directs National Grid to revise its decoupling adjustment mechanism accordingly.

4. Treatment of New Customers

For new customers added into the system (i.e., customers who are connected to the Companies' system after the test year), the Companies proposed to delay their inclusion in the revenue decoupling mechanism until the Companies' next base rate case (Exh. NG-SFT-1, at 34). They argue that such treatment is important to enable the Companies to recover their costs when new customers provide benefits to the system, such as lower costs. (Exh. NG-SFT-1, at 34-35). The Attorney General states that if the Department approves the Companies' proposed retention of new customer revenues, the Department should eliminate from the COSS the incremental costs of new customers (Attorney General Brief at 33). ENE, however, argues that the Department should include all new customers in the decoupling mechanism and should not allow the Companies to retain the revenues associated with adding new customer meters (ENE Brief at 8-9).

Longstanding Department precedent regarding the ratemaking treatment of incremental revenues from new customers after rates have been set allows the company to retain those revenues until its next base rate case. D.P.U. 09-30 at 94 & n. 50, citing D.T.E. 05-27, at 75, 79, 80; D.T.E. 03-40, at 48; D.P.U. 88-67 (Phase I) at 282-284; D.P.U. 89-180, at 16-17. In D.P.U. 09-30, at 98-99, we found that it was still appropriate post decoupling to permit a gas utility to retain incremental revenues from new customers added after the test year in order to preserve the incentive to the gas utility to add new customers that should, in the long run, reduce the company's average cost of distribution service.[27]

With regard to C&I customers, if they were included in the decoupling mechanism, then the Companies would be able to retain only the C&I benchmark base revenue-per-customer when adding a new C&I customer to the distribution system, as a result of the Companies' aggregating all the C&I customers into one group. Consequently, the Companies would be able to retain far less revenues from these new large C&I customers than under the current system, where they are allowed to retain all the revenues billed to the customer. If such an approach were adopted, National Grid would require a substantially higher

[27] Regarding the addition of customers, the Department has found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 05-27, at 75, 79-80, citing D.T.E. 03-40, at 48; Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1989). The Department stated that existing customers receive benefits whenever the return on the incremental rate base exceeds the company's overall rate of return. D.T.E. 05-27, at 75, citing Boston Gas Company, D.P.U. 89-180, at 16-17 (1990).

contribution in aid of construction from the customer to recover the high cost of connecting a large load. In turn, this may provide a disincentive to connect larger and relatively more cost effective customers that would, in the long run, reduce the Company's average cost of distribution service.

In addition, we are not concerned that National Grid will have an incentive to maximize the consumption level of new customers in order to maximize revenues under this approach. We believe that the benefits of increasing the Companies' incentive to obtain new gas customers outweigh the potential costs of the Companies having the incentive to maximize the consumption of those customers.

Further, National Grid stated that it tracked on an "ad hoc basis" how the annual usage and the cost of adding new customers have changed over time; however, the information provided did not substantiate the change (Exh. AG-19-21; Tr. 1, at 70-73; RR-DPU-1; RR-AG-1,). Without this information, the Department is unable to make a finding as to whether the revenue requirements for new customers are comparable to those from existing customers. Consequently, the Department is concerned that the revenues provided to the Companies for serving new customers could deviate significantly from the cost incurred to serve them. Therefore, consistent with our findings in D.P.U. 09-30, at 94, 100, we will permit the Companies to retain the revenues from new customers until their next rate case by not including new customers in the reconciliation of the revenue decoupling mechanism. The Companies are directed to separately track the usage of new customers in the peak and off-peak seasons, as well as the cost to connect new customers by rate class,[28] and report such information as part of their seasonal revenue decoupling adjustment filing. See D.P.U. 09-30, at 100-101.

As noted above, the Attorney General argues that the Department should remove O&M costs associated with obtaining new customers from the cost of service to offset the revenues from new customers. In addition to retaining the revenues from new customers after rates have been set, longstanding Department precedent also allows a company to recover the O&M costs incurred in the test year associated with obtaining the new customer, such as the costs for new boilers, customer incentives for conversions, and sales commission, provided that certain requirements have been met. D.T.E. 05-27, at 213-220; D.P.U. 03-40, at 276-278. Therefore, the Department will not require the removal of O&M costs associated with obtaining new customers from the cost of service to offset the revenues from new customers. The issue of promotional costs is addressed further in Section X.T, below.

5. Treatment of Non-Heating to Heating Conversions

National Grid proposes that when existing residential customers convert from non-heating to heating services they be included in the revenue decoupling mechanism as heating customers. In other words, National Grid would retain the heating base revenue-per-customer, rather than the non-heating base revenue-per-customer that it would have retained if the customer not converted to heating services (Exhs. NG-SFT-1, at 35 & n.37; DPU-1-19, at 3).

[28] To the extent the Companies do not currently have a system to track the costs to connect new customers by rate class, we direct the Companies to develop such a system.

National Grid argues that such treatment is necessary to maintain its incentive to promote residential conversions, which will provide substantial benefits to all customers in setting rates in the future (National Grid Brief at III.10; National Grid Reply Brief at 24-25).

Alternatively, the Attorney General argues that the Department should reject National Grid's proposal to include residential non-heating to heating conversions in this way and, instead, require the Companies to credit the difference between the residential non-heating and heating base revenue-per-customer to ratepayers, particularly because National Grid failed to provide cost information supporting the need for additional revenues to cover the costs of converting these customers as required in D.P.U. 09-30, at 102 (Attorney General Brief at 30, citing Tr. 17, at 2240-2241). DOER recommends that the Department reject the Companies' proposal to retain incremental revenues associated with the conversion of existing customers from non-heating to heating service (DOER Brief at 4). DOER argues that if the Companies are recovering the marketing expenses associated with these upgrades, then there should be more than adequate incentive for the Companies to continue to market upgrades to their existing customers (DOER Brief at 6).

In D.P.U. 09-30, at 101-102, the Department permitted Bay State to retain the incremental revenues from existing residential customers who convert from non-heating to heating service, but only in the instances when the company was required to make incremental capital investments for the conversion. Otherwise, the Department required that Bay State credit back to customers revenues associated with existing non-heating customers who convert to heating service. The Department found that this approach was reasonable because it would allow the company the opportunity to recover the cost of its incremental investments associated with the conversion of existing non-heating customers to heating service D.P.U. 09-30, at 102. For existing non-heating customers where no incremental investments from the company are required to convert to heating service, the Department found it was reasonable and appropriate that the company provide such credit. D.P.U. 09-39, at 102.

In this case, both the Attorney General and DOER argue that the Companies will continue to market residential conversion from the non-heating to the heating rate and, therefore, it is not necessary to allow them to retain the additional revenues because they incur no incremental costs. However, National Grid has demonstrated that there is strong potential for conversions on its distribution system unlike the situation in Bay State (Exh. NG-SFT-1, at 35 n.37). As we noted above in Section IV.D.4, longstanding Department precedent regarding the ratemaking treatment of additional revenues from new customers after rates have been set allows the company to retain those revenues. D.P.U. 09-30, at 94, n. 50, citing D.T.E. 05-27, at 75, 79, 80; D.T.E. 03-40, at 48; D.P.U. 88-67 (Phase I) at 282-284; D.P.U. 89-180, at 16-17. Further, in D.P.U. 09-30, at 98-99, we found that it was still appropriate post decoupling to permit a gas utility to retain revenues from new customers added after the test year in order to preserve the inventive to the gas utility to add new customers that should, in the long run, reduce the company's average cost of distribution service.

Continuation of our longstanding ratemaking treatment will ensure that the benefits of the conversions ultimately flow to ratepayers in terms of lower rates along with the environmental benefits of heating with gas rather than alternative fuels (Tr. 1, at 29-31;

RR-AG-1). Thus, in regard to treatment of the incremental revenues, we find no reason to distinguish our treatment for new customers from our treatment for customers that convert from the non-heating residential rate to the heating residential rate. For these reasons, we approve the Companies' proposal to keep the incremental revenues (i.e., the difference in revenues per customer between heating and non-heating target revenue) associated with non-heating to heating service customer conversions.

In addition, consistent with the Department's goal of promoting the implementation of all cost-effective demand resources, the Department seeks to develop a reliable and consistent record with respect to: (1) the number of customers migrating from one rate class to another rate class; (2) the cost to convert customers from the residential non-heat rate to the heat rate; (3) the reduction in the number of existing customers by rate classes; (4) the addition of new customers by rate classes; and (5) the impact on customers' consumption behavior under revenue decoupling specific to National Grid. In the compliance filing to this Order, the Department directs the Companies to describe how they will provide the above-described information. Such information must be provided in each semi-annual revenue decoupling adjustment filing.

6. Review of Decoupling Mechanism

The Attorney General recommends that the Department conduct a multi-faceted policy evaluation of the Companies' revenue decoupling plan after a three-year period (Attorney General Brief at 29). Such investigation could run concurrent with, or as part of, the

Department's review of the Companies' three-year energy efficiency plans (Attorney General Brief at 29, citing Exh. AG-DED-1, at 29).[29]

At this time, the Department finds it unnecessary to mandate a formal three-year review of the Companies' revenue decoupling plan. We have required the Companies to provide all necessary and relevant information relating to the phenomenon of residential customer migration (see Section IV.D.5, above). Similarly, we have required the Companies to provide all the necessary and relevant information to track the number of customers, their usage, and associated revenues from those customers (see Section IV.D.5, above).

The Companies are directed to provide in each of their peak and off-peak revenue decoupling adjustment filings, a consistent and on-going record of all relevant information, so

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29 The Attorney General states that such review should include: (1) an analysis of monthly, seasonal, annual, and cumulative revenue deferrals and balances; (2) an analysis of any changes made to the deferral calculations; (3) a comparison of estimated deferrals to those suggested in the rate case; (4) an analysis of the potential impact of deferrals on earnings and overall returns; (5) an analysis of the bill impacts associated with the decoupling mechanism; (6) an analysis of the interest or carrying charges associated with the deferrals; (7) an analysis of the actual direct lost margin associated with the Companies' total and incremental demand side management efforts; (8) an analysis of usage differences between new and existing customers; (9) a comparison of the differences between new and existing customer use-per-customer; (10) an analysis of overall customer usage, use per customer, and customer growth, per class on a pre- and post-decoupling basis; (11) an analysis of customer migration during the three-year review period; (12) an analysis of the Companies' activities in supporting new customer growth including encouraging new and economic uses of natural gas; (13) a survey of customer perception, understanding, and acceptance of the decoupling mechanism; (14) the degree to which the Companies' corporate culture regarding the promotion of energy efficiency has meaningfully changed as a result of the adoption of revenue decoupling; and (15) an analysis of financial market perceptions of the Companies' revenue decoupling mechanism and its potential impact on earnings (Exh. DPU-AG-1-13).

that the Department can closely monitor the implementation of National Grid's revenue decoupling mechanism. To the extent that the implementation of decoupling may result in undesirable or unintended consequences that could result in unjust and unreasonable rates, then the Department, on its own motion pursuant to G.L. c. 164, § 93 and its general supervisory authority over gas distribution companies pursuant G.L. c. 164, § 76, may determine it necessary to investigate the propriety of such existing rates.[30]

7. Revenue Decoupling Recovery Adjustment

National Grid proposes to implement the semi-annual revenue decoupling adjustments through its LDAF and, accordingly, proposes certain amendments to its LDAC tariff (Exh. NG-AEL-4, at 35-36).[31] Under National Grid's proposal, the Companies' decoupling adjustment will be reviewed semi-annually along with the numerous other reconciling cost items in the LDAC.

As discussed above, the Companies will provide in each of their peak and off-peak revenue decoupling adjustment filings certain information so that the Department can closely monitor the implementation of the revenue decoupling adjustment. As such, we find that it is more appropriate to have a separate decoupling tariff and to review future decoupling

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30 In addition, the Attorney General may request that the Department initiate an investigation pursuant to G.L. c. 164, § 93 into the price of gas sold by National Grid.

31 This proposed recovery mechanism is different from what was approved in D.P.U. 09-30. In that proceeding, the Department approved a separate tariff, under which Bay State Gas currently operates, that establishes the procedures for the company to adjust on a semi-annual basis its rates for firm gas sales and firm transportation service in order to reconcile actual base distribution revenues with benchmark base distribution revenues. D.P.U. 09-30, at 25-26, 33, 117.

adjustments in a separate reconciliation proceeding and preserve for the LDAC the more customary reconciling cost items.[32] Accordingly, we direct the Companies to remove any decoupling-related elements from their LDAC tariffs and file, as part of their compliance filing, a separate decoupling tariff, with appropriate formulas, definitions, and calculations, consistent with the Department's findings and directives in this Order.

Finally, National Grid proposes that the Companies file their proposed decoupling adjustments at least 45 days prior to the effective dates of the November 1st peak period revenue decoupling adjustment and the May 1st off-peak period revenue decoupling adjustment (Exhs. NG-SFT-1, at 32; NG-AEL-1, at 25; NG-AEL-7). We find that this proposal does not afford the Department sufficient time to review future proposed decoupling adjustments. Accordingly, we direct the Companies to file their proposed decoupling adjustments at least 90 days prior to the effective dates of the November 1st peak period revenue decoupling adjustment and the May 1st off-peak period revenue decoupling adjustment.[33]

8. Conclusion

With the modifications as discussed above, the Department finds that the Companies' proposed decoupling mechanism is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B. The proposed decoupling mechanism appropriately aligns the

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32 The Department approved a separate decoupling tariff for Bay State in D.P.U. 09-30.

33 Although we have determined that the Companies' revenue decoupling adjustment will not flow through the LDAC, we note that these filing deadlines are consistent with requirements for LDAC related reconciliation filings. See D.P.U. 10-GAF-O1 through D.P.U. 10-GAF-O8 Hearing Officer Memo Filing Procedures, Local Distribution Adjustment Factor Filings, May 14, 2010.

financial interests of the Companies with the efficient deployment of demand resources and will ensure that the Companies are not harmed by decreases in sales associated with an increased use of demand resources. Further we find that operation of the Companies' proposed revenue decoupling mechanism, as modified, will result in just and reasonable rates. Accordingly, the Companies' proposed revenue decoupling mechanism, as modified herein, is approved.[34]

V. NET INFLATION ADJUSTMENT FACTOR PROPOSAL

A. Introduction

In order to address the inflationary pressures that the Companies face, National Grid proposes to adjust Boston Gas-Essex Gas' and Colonial Gas' rates annually by applying formula-based adjustments to the O&M component of the cost of service approved by the Department in this proceeding (Exh. NG-LRK-1, at 6).[35] National Grid's proposed net inflation adjustment factor accounts for the impact of inflation minus a productivity offset of 0.52 percent.

The Attorney General opposes National Grid's proposed net inflation adjustment factor (Attorney General Brief at 44). Alternatively, if the Department adopts a net inflation adjustment factor for National Grid, the Attorney General offers her own productivity offset

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[34] With the filing of this base rate proceeding and the implementation of decoupling, Colonial Gas' recovery of lost base revenues, including those recovered as exogenous costs, is eliminated (Exhs. NG-AEL-1, at 13-14; DPU-1-15, Att.; see also D.T.E. 98-128, at 54).

[35] National Grid also proposes to recover some of its incremental capital costs through a TIRF as discussed in Section VI, below (Exh. NG-NS-1, at 30-32).

calculation of 1.12 percent (Attorney General Brief at 48-49, citing Exh. AG-DED-2, Sch. DED-8). No other party commented on this issue.

B. National Grid's Proposal

National Grid proposes to annually adjust the O&M amount approved in this proceeding by (1) an annual growth in inflation measure, which can grow each year at different rates, minus (2) a productivity offset that will be fixed for all years that the adjustment factor is in effect (Exh. NG-LRK-1, at 8). National Grid proposes to use the gross domestic product price index ("GDP-PI"), an official measure of price inflation in the U.S. economy, as an inflation measure (Exh. NG-LRK-1, at 8). Specifically, National Grid proposes to measure inflation as the change in the four quarter average of the GDP-PI for the year ending June of the filing year and the four-quarter average of the GDP-PI for the year ending June 2011 (Exhs. NG-LRK-1, at 8; NG-AEL-4, at 37).

National Grid's proposed a net inflation adjustment factor net of O&M partial factor productivity gains that gas distributors can be expected to make because, National Grid states, partial factor productivity gains reduce O&M costs (Exh. NG-LRK-1, at 12). In addition, National Grid states that its proposed net inflation factor also reflects inflation in the prices paid for the O&M inputs that are purchased directly by gas distributors (Exh. NG-LRK-1, at 12).

With respect to the proposed productivity offset, the Companies performed a research study on gas distribution O&M input price trends in the Northeast (Exh. NG-LRK-1, at 13). National Grid states that the results of this study show that O&M input prices for Northeast gas distributors increased at an average annual rate of 2.97 percent over the period 1998 through 2008 (Exh. NG-LRK-1, at 14). Further, the Companies state that the GDP-PI increased at an average annual rate of 2.38 percent over the years 1998 through 2008 (Exh. NG-LRK-1, at 15). Accordingly, National Grid contends that annual inflation in O&M input prices for gas distributors in the Northeast exceeded GDP-PI inflation by 0.59 percent on average (Exh. NG-LRK-1, at 15). Thus, the inflation differential component of National Grid's proposed productivity offset is negative 0.59 percent[36] (i.e., 2.38 percent - 2.97 percent = -0.59 percent) (Exh. NG-LRK-1, at 15).

The Companies prepared a second research study on gas distribution O&M partial factor productivity trends (Exh. NG-LRK-1, at 15).[37] The Companies state that results of this research study show that O&M partial factor productivity for gas distributions in the Northeast increased at an average annual rate of 0.51 percent in the years 1998 through 2008 (Exh. NG-LRK-1, at 16). The Companies also propose to include a consumer dividend of

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[36] National Grid states that this component of the productivity factor is negative because gas distributors' O&M input prices tend to grow more rapidly than the GDP-PI (Exh. NG-LRK-1, at 15).

[37] The Companies developed estimates of O&M input price and partial factor productivity trends for the Northeast gas distribution industry using Global Insight data (Exh. NG-LRK-2, at 1). There were 22 gas distributors in the Northeast sample (Exh. NG-LRK-2, at 1). These companies serve 76 percent of gas distribution customers in the region (Exh. NG-LRK-2, at 1). The study excluded pensions and benefits from the calculation of O&M input prices because National Grid is proposing to recover changes in these costs directly through a reconciling mechanism (Exh. NG-LRK-2, at 1).

0.60 percent, based on relevant regulatory precedents in Massachusetts and other jurisdictions, empirical study and professional judgment (Exhs. NG-LRK-1, at 17-21; DPU-1-14).[38]

Based upon the results of these studies the Companies propose a productivity offset of 0.52 percent for the O&M net inflation adjustment formula (Exh. NG-LRK-1, at 16). This offset is based on: (1) the estimated differential between GDP-PI inflation and O&M input prices for Northeast gas distributors of negative 0.59 percent; plus (2) the estimated O&M partial factor productivity trend for Northeast gas distributors of 0.51 percent, and (3) a consumer dividend of 0.60 percent (Exh. NG-LRK-1, at 16). The sum of these three components is 0.52 percent (i.e., -0.59 percent + 0.51 percent + 0.60 percent = 0.52 percent).

National Grid states that the O&M net inflation adjustment factor will apply to the base distribution rates set in this proceeding by the Department for Boston Gas-Essex Gas and Colonial Gas (Exh. DPU-1-1). The Companies propose to collect the net inflation adjustment factor as a component of the LDAF through a per therm charge applied at the same rate to all firm gas sales and firm transportation sales (Exh. NG-AEL-4, at 36-37, 56).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the proposed net inflation adjustment mechanism is conceptually flawed and inconsistent with the Department's incentive regulation principles

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[38] The consumer dividend reflects expected future gains in productivity due to the move from cost-of-service regulation to performance based regulation. See, e.g., D.P.U. 96-50 (Phase I) at 278–279.

(Attorney General Brief at 33). In particular, the Attorney General claims that National Grid's proposed net inflation factor is considerably different from Boston Gas's PBR plan approved in D.T.E. 03-40, which included both a fixed term and an earnings sharing mechanism (Attorney General Brief at 34).

The Attorney General argues that the lack of a fixed term in the Companies' net inflation proposal is inconsistent with Department precedent and fails to provide the Companies with the necessary discipline to achieve operating efficiencies (Attorney General Brief at 35-36, citing D.T.E. 01-56, at 10; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66). The Attorney General also argues that the absence of an earnings sharing mechanism in the net inflation proposal is inconsistent with Department precedent and will allow the Companies to increase prices and retain earnings benefits that may arise from regulatory lag without sharing any such gains with ratepayers (Attorney General Brief at 37).

In addition, the Attorney General argues that the Companies' have failed to demonstrate that they need a net inflation adjustment factor (Attorney General Brief at 42). The Attorney General contends that, while the Companies claim that O&M inputs purchased by the Companies have increased in cost over time, there is no definitive evidence to establish that overall industry cost trends for O&M inputs are unmanageable (Attorney General Brief at 42). Rather, the Attorney General asserts that the evidence reveals that over the past ten years, O&M input price inflation was only slightly higher than inflation (Attorney General Brief at 43, citing Exh. NG-LRK-2, at 9). Thus, the Attorney General opines that the source of the Companies' problems is not price inflation but their own inefficient cost performance over the past several years relative to the industry and their regional peers (Attorney General Brief at 43).

Further, the Attorney General argues that the Companies' net inflation factor proposal is flawed and has already been rejected by the Department in D.P.U. 09-39 (Attorney General Brief at 43).[39] Specifically, the Attorney General contends that the Department rejected a similar net inflation proposal for Massachusetts Electric Company and Nantucket Electric Company in their last rate case (Attorney General Brief at 43-44, citing National Grid, D.P.U. 09-39 (2009)). According to the Attorney General, there are sufficient similarities between the two net inflation proposals to warrant the denial of National Grid's proposal in the instant proceeding (Attorney General Brief at 44-48).

Finally, the Attorney General recommends that if the Department approves the use of a net inflation factor, it should adopt an alternative net inflation factor (Attorney General Brief at 48). In particular, the Attorney General recommends the use of an alternative productivity offset calculation of 1.12, which is based upon a net inflation differential of negative 0.03, a productivity offset of 1.34, a consumer dividend of 0.06, and a three-year accumulated inefficiencies factor of 0.20[40] (Attorney General Brief at 48, citing Exh. AG-DED-1, at 3).

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[39] The Attorney General argues that National Grid used a flawed O&M expense profile allocation in its O&M partial factor productivity and input price study (Attorney General Brief at 45-48). Further, the Attorney General contends that National Grid inappropriately used a consumer dividend that is based on Canadian experience with a group of electric distribution companies (Attorney General Brief at 45).

[40] This factor compensates consumers for some of the inefficiencies the Companies have built up under cost-of-service ratemaking. According to the Attorney General, it is expected to take approximately three years to bring National Grid's expected costs into

The Attorney General offers an input price and productivity study in support of her recommendations (Attorney General Brief at 49, citing Exh. AG-DED-2, Sch. DED-8).

2. National Grid

National Grid states that prices of O&M inputs purchased by the Companies increase over time (Exh. NG-LRK-1, at 6). National Grid argues that some of the input prices routinely increase at rates that exceed the overall rate of inflation as measured by the rate of change for the GDP-PI (Exh. NG-LRK-1, at 6, 15). National Grid states that the Companies have little control over the increases in O&M costs associated with these expense items (Exh. NG-LRK-1, at 6). Thus, National Grid contends that input price inflation will put upward pressure over time on the Companies' O&M costs (Exh. NG-LRK-1, at 6).

According to National Grid, in the absence of an O&M net inflation adjustment mechanism, the Companies will be forced to file more frequent rate cases to recover the increase in their O&M costs (National Grid Brief at V.19; Exh. NG-LRK-1, at 7). National Grid states that these rate filings will involve costs that are ultimately recovered from ratepayers (Exh. NG-LRK-1, at 7). In addition, National Grid states that frequent rate cases make it more difficult for the Companies to pursue long-term strategies that contain the growth in O&M costs (Exh. NG-LRK-1, at 7). National Grid argues that a formula-based O&M adjustment mechanism is a more efficient means of recovering growth in the Companies' O&M costs than the alternative of more frequent rate cases (Exh. NG-LRK-1, at 7).

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line with its peer utilities (Attorney General Brief at 48-49, citing Exh. AG-DED-1, at 3). Accordingly, the Attorney General contends that, after three years, the accumulated inefficiencies factor should be removed from the Companies' productivity offset, resulting in an productivity offset of .92 (Attorney General Brief at 48-49).

Therefore, National Grid argues that its net inflation adjustment proposal is consistent with the Department's objectives of managing costs and should be approved (National Grid Brief at V.19-20).

Regarding the Attorney General's opposition to the Companies' proposal that the O&M net inflation adjustment formula has no defined term, National Grid states that the Companies have not proposed a defined term because, in the context of PBR, the Department has not recently accepted a term of less than ten years (National Grid Brief at V.6, citing D.T.E. 05-27, at 399-400; D.T.E. 03-40, at 496-497). According to National Grid, a ten-year term for the net inflation adjustment is not reasonable for a number of reasons including its substantial infrastructure related capital requirements, even with a TIRF, and operating costs that increase at a rate greater than the rate of inflation (National Grid Brief at V.6, citing Exh. NG-LRK-2, at 9, Table 4). Further, National Grid argues that a ten-year term is outside the mainstream of North American regulatory practice (National Grid Brief at V.6, citing Exh. Sch. NG-LRK-Rebuttal-1).

Further, National Grid contends that, given the lack of experience in Massachusetts with revenue decoupling and a capital cost recovery mechanism like the TIRF, the extent to which these two ratemaking mechanisms will assist the Companies in extending the time period between base rate cases is unknown and, therefore, any selection of a defined term would be arbitrary (National Grid Brief at V.7).

Regarding the Attorney General's opposition to the Companies' proposal that it does not contain an earnings sharing mechanism, National Grid argues that the Department has established the earnings sharing mechanism as a protection against the adoption of incorrect productivity factors (National Grid Brief at V.9, citing D.T.E. 05-27, at 404; D.P.U. 96-50, at 325). However, National Grid argues that the earnings sharing mechanisms historically approved by the Department have contained overly broad bandwidths that neither provide a company with adequate protection from a productivity factor that understates a company's revenue needs nor provide customers with an adequate share of productivity gains that occur (National Grid Brief at V.9, 10). Moreover, National Grid argues that experience has shown that the productivity factor is unlikely to over-compensate the utility because increases in gas distribution costs exceed the rate of inflation and non-TIRF related capital investments must still be made (National Grid Brief at V.10).

National Grid disputes the existence of any technical flaws in its O&M input price and productivity studies as alleged by the Attorney General (National Grid Brief at V.13). Further, regarding the Attorney General's alternative productivity offset proposal, National Grid claims that it is flawed and should be rejected (National Grid Brief at V.19).[41]

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[41] Specifically, National Grid argues that the Attorney General's productivity offset proposal is flawed because: (1) it assumes a value of zero for the U.S. O&M partial factor productivity growth term; (2) it fails to include in the productivity offset calibration the trend in O&M partial factor productivity for the U.S. economy; (3) the estimates of O&M partial factor productivity and input price growth do not exclude pension costs; (4) it fails to control for aggregation bias in the O&M partial factor productivity study; (5) it includes an accumulated inefficiencies factor as part of the overall productivity offset; and (6) it uses an inappropriate method to benchmark costs to evaluate the efficiency of Boston Gas' O&M expenses (Exh. NG-LRK-Rebuttal-1, at 34-45).

D. Analysis and Findings

In D.P.U. 07-50-A at 49-50, the Department recognized that changes in a distribution company's costs could arise from inflationary pressures on the prices of the goods and services it uses. The Department stated that we would consider company-specific proposals that adjust its target revenue to account for inflation and that a company would bear the burden of demonstrating the reasonableness of its proposal. D.P.U. 07-50-A at 50.

National Grid's proposed O&M net inflation adjustment mechanism allows the Companies to adjust their annual target revenue level to account for the impact of inflation (as measured by the GDP-PI), minus a productivity offset equal to 0.52 percent (Exh. NG-LRK-1, at 16). The Companies argue that the net inflation adjustment is necessary to address the various input price inflationary pressures that the Companies face. The Department must evaluate whether the proposed O&M net inflation adjustment mechanism should be approved, based on the Companies' specific circumstances and the other ratemaking mechanisms established by this Order.

The Companies calculated their proposed productivity offset based on two research studies of gas distribution O&M input price trends in the Northeast and of gas distribution O&M partial factor productivity trends (Exh. NG-LRK-1, at 13, 15). The Attorney General alleges flaws in the manner in which the Companies determined their proposed productivity offset. The Attorney General states that if the Department approves a net inflation adjustment mechanism, it should reject the Companies' proposed productivity offset and replace it with an offset equal to 1.12 percent (Attorney General Brief at 48).

The purpose of a net inflation adjustment mechanism is to provide additional revenues each year that the Companies need in order to cope with inflationary increases in their O&M expenses. In order to ensure that the Companies do not recover more revenue through the net inflation adjustment mechanism than is required to compensate them for inflationary pressures on their O&M costs, the Companies propose a productivity offset, including a consumer dividend that considers company-specific circumstances. The Department finds that in the instant case, an O&M net inflation adjustment mechanism is unwarranted for the following reasons.[42]

First, the Department stated that we would consider company-specific proposals that adjust target revenues to account for inflation because we were of the view that in decoupling their rates from revenues, gas and electric distribution companies might forgo revenue growth that, according to the companies, was needed to mitigate inflationary pressures on their operations. D.P.U. 07-50-A, at 39. However, in the instant case, National Grid's revenue-per-customer decoupling model allows the Companies to retain additional revenues from customer growth. Further, National Grid has stated that it has the potential to add a significant number of customers to its system (Exh. NG-SFT-1, at 35 n.37). Therefore, we find that increased revenues from customer growth will mitigate the potential increase in O&M costs from inflation.

[42] Because we reject National Grid's proposed net inflation adjustment mechanism, we need not reach the issue of whether the Companies developed an acceptable inflation measure and productivity factor.

Second, we note that the formula in the Companies' proposed O&M net inflation adjustment mechanism was a single component (i.e., the price cap formula) of a more comprehensive PBR plan. Simply severing one aspect of the PBR plan and applying it to the Companies' O&M expenses because it provides an inclining stream of revenues to mitigate inflation disregards the other elements of the plan that provide customer benefits, such as a fixed term, sufficient in duration to capture anticipated savings that require a multi-year pay back, or an earnings sharing mechanism that protects ratepayers in the event that the Companies' earnings become excessive.

Third, the Department notes that, under its decoupling plan, as compared to a PBR plan or a rate freeze, National Grid retains the ability to file for rate relief as it deems necessary pursuant to G.L. c. 164, § 94. As such, the Department finds that National Grid has the opportunity to address increase costs, such as those caused by inflation, by petitioning the Department to establish new rates. Such filings allow the Department and intervenors the opportunity to examine not only the purported increases in O&M costs but also the Companies' investment in plant and return on plant, the assignment of costs to rate classes, and the proper rate design.

In an era of low inflation that is unprecedented in recent history, it is difficult for the Companies to demonstrate that an inflation adjustment factor is warranted. The Companies claim the absence of such an adjustment will lead to more frequent, and even perhaps annual, rate filings. We are not persuaded. By contrast, we find that adoption of an inflation adjustment mechanism may lead to rate case filing intervals that are too long, particularly when the Companies are allowed to establish a TIRF to recover costs associated with replacement of leak-prone mains and associated services.

Because the Companies' revenue-per-customer decoupling plan and TIRF are new ratemaking mechanisms, the Department must closely examine how each mechanism achieves its intended goals and how the implementation of each mechanism impacts rates and the financial wellbeing of the Companies before considering the adoption of additional reconciling mechanisms such as the net inflation adjustment factor.[43] See D.P.U. 07-50-A at 50. Therefore, for the reasons discussed above, we find that an inflation adjustment mechanism is not warranted at this time.

VI. TARGETED INFRASTRUCTURE RECOVERY FACTOR PROPOSAL

A. Introduction

As of December 31, 2009, Boston Gas-Essex Gas' and Colonial Gas' distribution systems had a total of 10,915 miles of mains (Exh. DPU-6-14, Att.; RR-DPU-21;).[44] National

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43 Moreover, the Department gives careful consideration to the formation of any new fully reconciling cost mechanism. Specific criteria the Department considers when determining whether to allow a new fully reconciling mechanism include whether the costs at issue are: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control. See e.g., D.T.E. 05-27, at 183-186; D.T.E. 03-47-A, at 25-28, 36-37; D.T.E. 98-27, at 6, 28.

44 This total includes: (1) 1,150 miles of non-cathodically protected (also referred to as "unprotected") bare steel mains; (2) 189 miles of cathodically protected bare steel mains; (4) 2,440 miles of cathodically protected coated steel mains; (4) 613 miles of non-cathodically protected coated steel mains; (5) 2,058 miles of small diameter (i.e., less than or equal to eight inches) cast iron and wrought iron mains; (6) 380 miles of large diameter (i.e., greater than eight inches) cast iron and wrought iron mains; and (7) 4,086 miles of plastic mains (RR-DPU-21; Exh. DPU-6-14, Att.).

Grid's distribution system is one of the oldest systems in the United States and the Companies contend that it includes a relatively large portion of leak-prone facilities (Exh. NG-JBH-1, at 13-14).[45] Like other Massachusetts gas local distribution companies ("LDCs"), National Grid is in the process of replacing its bare steel infrastructure and other leak-prone facilities (Exh. NG-JBH-1, at 9-10; Tr. 4, at 374). National Grid proposes to implement a targeted infrastructure replacement program and recovery factor ("TIRF") designed to accelerate the replacement of leak-prone mains and associated services (Exhs. NG-NS-1, at 7-8; NG-JBH-1, at 3-4). Specifically, National Grid's proposed TIRF is designed to allow the recovery of the annual revenue requirement associated with the replacement of non-cathodically protected steel and small diameter cast iron and wrought iron distribution mains and other eligible facilities.[46]

National Grid's proposed TIRF allows for annual recovery of a revenue requirement associated with incremental infrastructure investments over a ten-year initial term (Exhs. NG-NS-1, at 7; NG-JBH-1, at 3).[47] National Grid states that its proposed TIRF is designed to achieve the following milestones: (1) the elimination of 160 miles of leak-prone mains inventory and associated services per year; (2) the elimination of 5,000 non-cathodically

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[45] National Grid's 2008 aggregate leak rate was 0.64 leaks per mile compared to the 2008 average aggregate leak rate of 0.29 leaks per mile for a peer group of 22 regional LDCs (Exhs. NG-JBH-1, at 11; AG-7-4, Att.).

[46] National Grid defined eligible facilities to include mains (Account 367), services (Account 380), meters (Account 381), meter installations (Account 382), and house regulators (Account 383) (RR-DPU-8; RR-DPU-118, Att. A at 11).

[47] National Grid proposes to submit: (1) a midpoint progress report after five years of program implementation, with proposals for any program adjustments; and (2) a detailed program evaluation report and recommendation for going forward action after ten years of program implementation (Exh. NG-JBH-1, at 28).

protected leak-prone steel services per year through a dedicated service replacement program, with high-pressure inside services prioritized for replacement; and (3) an average aggregate leak rate of 0.32 leak per mile, or a 50 percent reduction from its 2008 average aggregate leak rate (Exhs. NG-JBH-1, at 11, 28; AG-7-4, Att.).

Under National Grid's proposed TIRF, the annual incremental targeted infrastructure gross plant investments allowable for inclusion in the TIRF cannot exceed the annual incremental non-growth plant investments less the annual depreciation expense approved by the Department in the instant case (RR-DPU-118, Att. A at 4; see RR-DPU-107, at 2; RR-DPU-119, at 3). National Grid provided a forecast of its annual capital investments to be supported by the proposed TIRF based on 2009 cost data (Exh. NG-JBH-3; Tr. 5, at 652; RR-DPU-24, Att. at 5, citing Exh. DPU-19-14). National Grid expects to accelerate its mains replacement investments through 2015 and then to continue its level of investment through the remaining years of the program (Tr. 5, at 652-653). For 2011 through 2016, National Grid's annual investments for its mains and service replacements are forecast to be \$173.2 million, \$193.9 million, \$219.8 million, \$240.5 million, \$261.2 million, and \$261.6 million, respectively (RR-DPU-24, Att. at 5). For the remaining four years of the ten-year term of the proposed TIRF, National Grid's projected investments for mains and service replacements are forecast to be \$261.7 million per year (RR-DPU-24, Att. at 5).

These annual expenditures include the replacement of 50 miles per year of unprotected bare steel mains and small diameter cast iron and wrought iron mains of 105 miles, 125 miles, 150 miles, 170 miles in 2011, 2012, 2013, 2014, respectively, and 190 miles annually from

2015 to 2020 (RR-DPU-24, Att. at 5). More than 90 percent of the annual planned capital investments are for the Boston Gas distribution system (RR-DPU-24, Att. at 1-5). For example, of the planned total replacement of 50 miles per year of cathodically unprotected bare steel mains from 2011 to 2020, 40.2 miles of such mains replacement will be performed in the Boston Gas service area (RR-DPU-24, Att. at 1, 5).

National Grid proposes to recover the annual TIRF revenue requirement in the LDAF through a per therm charge applied to all firm throughput for both Boston Gas-Essex Gas and Colonial Gas (Exh. NG-MDL-1, at 87). To implement the TIRF, National Grid proposes to amend its existing LDAC tariff by inserting Section 6.11 (Exhs. NG-MDL-1, at 85; NG-AEL-1, at 24; RR-DPU-118, Att. A, at 1, 4-5). National Grid proposes to make its annual TIRF filings on May 1^{st} for charges effective November 1^{st} to recover the revenue requirement associated with the targeted infrastructure projects completed during the previous year (Exh. NG-MDL-1, at 87).

As discussed in greater detail below, National Grid's proposed TIRF annual revenue requirement includes depreciation, property taxes, a return based on pre-tax weighted average cost of capital ("WACC"), carrying costs associated with the billing delay of the annual TIRF revenue requirements during the period January 1^{st} through November 1^{st} following the calendar year of TIRF investments, and carrying costs associated with any allowed deferrals (Exh. NG-MDL-1, at 85-86; NG-NS-1, at 26; RR-DPU-118, Att. A at 4).

The Department approved a TIRF for Bay State in D.P.U. 09-30. National Grid's proposed TIRF operates in a similar manner except that, unlike Bay State, National Grid proposes to include the replacement of small diameter cast iron and wrought iron mains in its program (Exhs. NG-MDL-1, at 85; NG-JBH-1, at 3-4).[48] In addition, the TIRF approved in D.P.U. 09-30 did not include a carrying charge on TIRF revenue requirement to cover the ten-month billing delay (Exh. NG-MDL-1, at 86). Finally, as discussed below, National Grid's proposal includes a three percent "fixed cap" on the TIRF revenue requirement based on total revenues approved in this proceeding and a three percent "billing cap" based on actual total revenues (RR-DPU-118, Att. at 4, 5). In D.P.U. 09-30, at 120-130, the Department approved a one percent cap for Bay State based on actual total revenues.

B. National Grid's Proposal

1. Caps on TIRF Revenue Requirement

National Grid proposes to limit the total annual incremental increase in the TIRF revenue requirement by a fixed cap equal to three percent of Boston Gas-Essex Gas' and Colonial Gas' respective total revenues from firm sales and transportation throughput with transportation revenues being adjusted by imputing National Grid's cost of gas charges (RR-DPU-118, Att. A at 4; see RR-DPU-56, at 2; RR-DPU-57, Att. A at 4, 5).[49] National

48 National Grid states that although non-cathodically protected steel and small diameter cast iron and wrought iron facilities comprise 36 percent of its distribution infrastructure, these facilities account for approximately 93 percent of the system leaks occurring in a given year (Exh. NG-JBH-1, at 4, 8).

49 Based on National Grid's proposed total revenue requirement in this case, the three percent fixed cap is equal to $41,595,183 for Boston Gas-Essex Gas and $10,445,758 for Colonial Gas (RR-DPU-118, Att. A at 4; see RR-DPU-56, at 1; RR-DPU-57, Att. A at 4). While this proposed cap limits the rate impact to customers, it does not limit the level of infrastructure investment that can be undertaken in a given year (Exh. NG-MDL-1, at 88).

Grid proposes to further limit the incremental TIRF revenue requirement that could be collected in any year by a billing cap equal to three percent of the total actual revenues from firm sales and transportation throughput during the most recent calendar year, with the transportation revenues being adjusted by imputing National Grid's cost of gas charges for that annual period (RR-DPU-118, Att. A at 4-5; see RR-DPU-56, at 2; RR-DPU-57, Att. A at 5). National Grid proposes to defer the incremental annual TIRF revenue requirement in excess of the billing cap and less than the fixed cap for recovery in a later filing (RR-DPU-118, Att. A at 5; see RR-DPU-56, at 2; RR-DPU-57, Att. A at 5).[50]

2. Carrying Charges on Billing Delay

National Grid proposes to collect carrying charges related to the billing delay associated with the annual TIRF revenue requirement, from January 1st to November 1st following the end of the calendar year of the annual TIRF investment period (RR-DPU-56, at 2). Such carrying charges would be assessed on the lesser of: (1) the annual TIRF revenue requirement; or (2) the fixed cap established in the instant case (RR-DPU-56, at 2). Under the proposed TIRF, the carrying charge associated with the billing delay would be calculated using National Grid's pre-tax WACC as determined in the instant case (RR-DPU-56 at 2).

3. Carrying Charge on Deferrals

Under National Grid's proposed TIRF, all or a portion of any deferral plus carrying costs can be included in a subsequent annual TIRF filing provided that the sum of the

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50 This limitation on recovery does not affect the calculation of the annual incremental TIRF revenue requirement in subsequent periods (Tr. 10, at 1350-1362).

incremental TIRF revenue requirement in that subsequent year plus the deferral, or portion thereof, does not exceed the billing cap for that year (RR-DPU-118, Att. A at 5; RR-DPU-56, at 2; RR-DPU-57, Att. A at 5). National Grid proposes to apply carrying charges on any average deferred balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates (RR-DPU-118, Att. A at 5; RR-DPU-56, at 2; RR-DPU-57, Att. A at 5).[51]

4. TIRF Savings and O&M Offsets

Under its proposed TIRF, National Grid would deduct targeted infrastructure replacement program savings as an offset to its O&M expense, reflecting reduced leak repair activity (Exh. NG-MDL-1, at 87; RR-DPU-118, Att. A at 12). The savings would be applied to reduce the TIRF revenue requirement (Exhs. NG-MDL-1, at 87; NG-MDL-5-Boston Gas at 2-6; NG-MDL-5-Colonial at 2-6; RR-DPU-29, Att A at 2).

National Grid's proposed O&M offsets are $4,557 per mile for Boston Gas-Essex Gas and $2,518 per mile for Colonial Gas (RR-DPU-118, Att. A at 12). These O&M offsets represent the weighted average test year cost of leak repairs on non-cathodically protected steel and small diameter cast iron and wrought iron mains on Boston Gas-Essex Gas' and Colonial Gas' systems (Exhs. NG-JBH-1, at 26; DPU-6-8; AG-7-9, Att.; RR-DPU-27). National Grid proposes to determine the targeted infrastructure replacement program savings by multiplying the O&M offset per mile by the total miles of non-cathodically protected steel and small

[51] Until fully recovered, the deferred balance would accrue interest at the prime rate; however, the amount of any potential deferral would be limited by the imposition of the fixed cap (RR-DPU-56, at 2).

diameter cast and wrought iron mains replaced during the annual TIRF investment period (RR-DPU-118, Att. A at 12; Exhs. NG-MDL-1, at 87; NG-MDL-5-Boston Gas at 2-6; NG-MDL-5-Colonial at 2-6; NG-JBH-1, at 26).

5. Per Therm Charge for the TIRF

National Grid proposes to recover the annual TIRF revenue requirement in the LDAF through a per therm charge applied to all firm throughput for both Boston Gas-Essex Gas and Colonial Gas (Exh. NG-MDL-1, at 87).[52] Once the targeted infrastructure investments are included in rate base in a subsequent rate case, National Grid states that the costs will be treated in the same manner as other distribution main costs that are included in the cost allocation and recovered through base rates (Exh. NG-MDL-1, at 87-88).

6. Ratemaking Treatment of Overhead and Burden Costs

With or without the proposed TIRF, National Grid's labor overhead expense and clearing account burdens are charged to TIRF-related projects in the same manner for all capital projects (i.e., a percentage is charged to direct and contract labor in accordance with National Grid's capitalized burden process) (RR-DPU-107, at 1; RR-DPU-119, at 1).[53] These

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52 National Grid proposes to make separate TIRF filings for Boston Gas-Essex Gas and Colonial Gas system, although National Grid proposed only one LDAC tariff revision that covers both Companies (RR-DPU-118, Att. A, at 26; see: Exh. NG-AEL-4, at 54). During the proceeding, National Grid submitted a revised LDAC tariff that includes separate three percent fixed caps, O&M offsets, TIRF revenue requirements and infrastructure recovery factors for Boston Gas-Essex Gas, Colonial Gas (Cape Cod), and Colonial Gas (Lowell) (RR-DPU-57, Att. A, at 4-5, 24; RR-DPU-27; Tr. 10, at 1363).

53 Labor overhead expenses include: health and hospitalization expense; pension costs; pension benefits other than pension; payroll taxes charged to expense; unproductive

percentages are currently trued up on a quarterly basis so that total overheads and burdens are appropriately allocated to a company's overall capital program and are fully cleared by year-end to eligible projects (RR-DPU-107, at 1; Tr. 13, at 1829-1838).[54]

An issue identified in this proceeding was the possibility of an unintended double recovery through the TIRF of labor overheads and clearing account burdens that are included in base rates and also recovered through National Grid's Pension and Pension Benefits Other Than Pensions Reconciliation Adjustment Factor ("PRAF") (Tr. 5, at 689-691; Tr. 18, at 2590-2596; Tr. 20, at 2931-2938, 2942-2943; RR-DPU-107). To address this concern, National Grid proposed a three-step process to prevent double recovery (RR-DPU-107, at 2; RR-DPU-119).[55]

The first step in the three-step process is designed to assure that National Grid is not double recovering costs associated with overheads and burdens through the TIRF. In its annual TIRF filing, National Grid proposes to compare the actual overheads and burdens charged to O&M expense in each year of the TIRF to the amount of O&M overheads and

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labor charged to expenses, incentive compensation, and union goals charged to expense; and other employee benefits (RR-DPU-119, Att. at 2). Clearing account burdens include stores costs charged to expense and transportation costs charged to expense (RR-DPU-119, Att. at 2).

54 The allocation of total overheads and burdens are done on a company-specific basis (Tr. 13, at 1818-1819; RR-DPU-81).

55 The adjustments made pursuant to National Grid's proposed three-step process would be for TIRF-related ratemaking purposes only and would not affect National Grid's accounting processes pursuant to generally accepted accounting principles ("GAAP") (RR-DPU-107, at 3).

burdens included in the base rates approved in this proceeding and the PRAF (RR-DPU-107, at 2; RR-DPU-119 at 2).[56] To the extent that actual O&M overheads and burdens are less than the amount included in base rates and the PRAF, National Grid would reduce the total capitalized labor overheads and burdens in a given year of its TIRF filing by the difference (RR-DPU-107, at 2). If the TIRF actual labor overheads and clearing account burdens charged to O&M expense exceed the level set in base rates plus the current amortization of deferred PRAF, then no such adjustment would be made (RR-DPU-119, at 2).

The second step is applied in order to demonstrate that the overall level of the actual capitalized labor overheads and clearing account burdens, as adjusted in the first step, are allocated equally to all capital projects in any given year, including TIRF projects (RR-DPU-119, at 3). National Grid states that this step is necessary because there is a potential for timing differences associated with National Grid's accounting processes that could result in an uneven allocation of capitalized labor overheads and burdens to individual capital projects (RR-DPU-119, at 3; RR-DPU-107, at 3; Tr. 13, at 1829-1838).

In the third step, a recovery cap based on the level of depreciation expense determined in this proceeding would be applied to the eligible TIRF investments calculated through steps 1 and 2, above (RR-DPU-119, at 3). This cap would limit the amount of TIRF-related

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[56] As part of its compliance filing to this Order, National Grid states that it will provide a schedule indicating the level of overheads and clearing account burdens recovered in base rates and the PRAF (RR-DPU-119, at 1; Att. at 1). The baseline amounts approved and recovered through base rates and the PRAF would be set until National Grid's next rate case with the exception of the amortization of deferred pension and PBOP costs which change annually in the PRAF (RR-DPU-119, at 1, Att. at 1).

investments to be recovered through the annual TIRF to a level that is equal to or less than the amount by which total annual capital expenditures exceed National Grid's annual depreciation expense (RR-DPU-107, at 2). Specifically, the TIRF cost recovery would be limited to the lesser of: (1) the total non-growth capital investments less the depreciation expense allowance included in base rates; and (2) actual TIRF capital investments (RR-DPU-107, at 2). The lesser of these two amounts would be further subject to the fixed cap described above (RR-DPU-107, at 2).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General advances several arguments against approval of National Grid's proposed TIRF. Alternatively, should the Department accept the TIRF, the Attorney General recommends certain modifications to the Companies' proposal. Her reasons for opposing the TIRF, the deficiencies noted, and her recommended modifications are described below.

b. TIRF Will Harm Customers and Benefit Shareholders

The Attorney General argues that the Department should reject National Grid's proposed TIRF mechanism as it will harm customers and enrich shareholders in several ways (Attorney General Brief at 56, 57). First, the Attorney General claims that no meaningful consumer benefits will materialize from the TIRF and any benefits that could arise are not a function of the TIRF but of the investment itself, which is already appropriately facilitated by Boston Gas' PBR (Attorney General Reply Brief at 13). Unlike Boston Gas' PBR, the Attorney General claims that the TIRF offers no measurable metrics to appropriately incent a company to achieve its goals and efficiencies (Attorney General Brief at 89, citing D.T.E. 05-27, at 46-49). The Attorney General argues that adopting a decoupling mechanism together with the TIRF as a special capital replacement mechanism, will incent National Grid to invest in capital improvements instead of O&M expenditures, even if such capital improvements represent sub-optimal solutions compared to non-capital production factors, because shareholders earn a return on capital investments but not on O&M expenses (Attorney General Brief at 57, citing D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 15). For example, the Attorney General claims that the TIRF will encourage National Grid to make additional but perhaps inefficient expenditures on mains replacements because the cost recovery process for expenditures on TIRF-related projects would be streamlined thereby providing an incentive to build up rate base and earnings for its shareholders under decoupling (Attorney General Brief at 89).[57] The Attorney General adds that National Grid will also have the incentive to distort labor and material costs upwards to the extent they can be capitalized and earn a return (Attorney General Brief at 58).

The Attorney General claims that National Grid has not offered any specific proposals for program accountability and that, without any such capital cost containment mechanism comparable to a PBR, the TIRF will enrich National Grid shareholders at the expense of

[57] The Attorney General states that while the decoupling mechanism may limit earnings growth from volumetric sales, it does not limit earnings growth on capital investments (Attorney General Brief at 56).

ratepayers (Attorney General Brief at 57, 78).[58] The Attorney General explains that the proposed TIRF shifts virtually all of the performance risk associated with National Grid's pipeline replacement activities to ratepayers (Attorney General Brief at 79, citing Ex. AG-DED-1, at 96).

In addition, the Attorney General claims that the TIRF is not needed for reliability purposes (Attorney General Brief at 79; Attorney General Reply Brief at 13). The Attorney General states that National Grid has made no claims or provided any information to demonstrate that its ability to provide safe, economic, and reliable service will be compromised without the TIRF (Attorney General Brief at 79, citing AG-DED-1, at 89; Attorney General Reply Brief at 19, citing Exh. AG-DED-1, at 89).[59] Further, the Attorney General claims that Boston Gas' current PBR has been designed to facilitate capital investment, including those investments needed to maintain public safety and reliability (Attorney General Brief at 79, citing Tr. 4, at 474; Attorney General Reply Brief at 19, citing Tr. 4, at 474).

The Attorney General also claims that the TIRF removes regulatory lag and will ultimately cause higher rates because National Grid will no longer have an incentive to

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58 The Attorney General states that while she fully supports capital investments expenditures necessary to maintain public safety, she does not agree that mechanisms such as the TIRF, with little performance and cost accountability, are the appropriate mechanisms for supporting these investments (Attorney General Brief at 79).

59 The Attorney General notes that the Rhode Island Public Utilities Commission rejected the TIRF proposal of Narragansett Electric Company, an electric affiliate of National Grid, because the company provided no evidence that safety and/or environmental performance would be compromised without the adoption of a similar infrastructure replacement rider (Attorney General Brief at 79-80).

minimize costs (Attorney General Brief at 80-81; Attorney General Reply Brief at 14).[60] Citing a report sponsored by the National Regulatory Research Institute ("NRRI"), the research arm for the National Association for Regulatory Utility Commissioners ("NARUC"), the Attorney General claims that regulatory lag is an important policy tool in controlling utility costs and investments which ultimately can lead to lower rates (Attorney General Brief at 80, 81, citing K. Costello, "How Should Regulators View Cost Trackers?" Washington, DC: NRRI).

Further, the Attorney General claims that the proposed TIRF will result in increased costs exceeding any benefits (Attorney General Reply Brief at 14). The Attorney General claims that National Grid's TIRF proposal omits any reasonable cost-benefit analysis and that the purported benefits that will arise from the TIRF have only been described in the most general terms (Attorney General Brief at 78). The Attorney General argues that National Grid's arguments fail to recognize that many of those benefits, such as public safety, service reliability, cost effectiveness, public convenience and customer satisfaction, municipal cost and convenience, and environmental and economic benefits, to the extent they exist, would have occurred under Boston Gas' current PBR (Attorney General Brief at 78, citing Exh. NG-JBH-1, at 25).

The Attorney General claims that National Grid's proposed TIRF is inconsistent with the TIRF recently approved for Bay State (Attorney General Brief at 81, citing D.P.U. 09-30,

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[60] Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates (Attorney General Brief at 80).

at 118-130).[61] The Attorney General argues that National Grid provided no evidence that its circumstances are sufficiently different from Bay State to warrant a different treatment and, therefore, Department should reject its TIRF (Attorney General Brief at 82). Alternatively, if the Department grants National Grid's proposed TIRF, the Attorney General argues that the Department should reject each element that does not comply with the standards set in D.P.U. 09-30 (Attorney General Brief at 82).

The Attorney General notes that the costs of the proposed TIRF are substantial, equal to an investment of $786 million for the five-year period 2010 through 2014 in the Boston Gas-Essex Gas service areas (Attorney General Brief at 57). The Attorney General argues that this amount is equal to 44 percent of Boston Gas-Essex Gas' test year plant in service for mains and services (Attorney General Brief at 57). The Attorney General also notes that the TIRF investment for Colonial Gas for that same period is estimated at $128 million, which is equal to 28 percent of test year plant mains and services investment (Attorney General Brief at 57, citing Exh. AG-DED-1, at 76-77).[62]

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[61] The Attorney General notes that the Bay State TIRF: (1) does not include carrying charges; (2) it is limited to recovery of replacement costs of unprotected steel mains and services and excludes cast iron and wrought iron mains; (3) was only approved for a fixed duration that was limited to the period between the date of the Order in D.P.U. 09-30 and the company's next rate case; and (4) annual revenue requirement is limited to an amount equal to one percent of the company's prior year's actual total firm revenues (Attorney General Brief at 81-82, citing Exh. AG-DED-1 at 90-91).

[62] The Attorney General contends that such a proposed ramp-up rate in mains replacement may stress the ability of the area to accommodate the program and drive up costs to other Massachusetts gas distribution companies (Attorney General Brief at 57-58, citing Exh. AG-CJM-1, at 9-10).

Finally, the Attorney General claims that the proposed TIRF mechanism is a formula rate that must be reviewed and approved by the Department pursuant to G.L. c. 164, § 94 (Attorney General Brief at 56, citing Consumers Organization For Fair Energy Equity, Inc. v. Department of Public Utilities, 368 Mass. 599, 605-606 (1975)). Accordingly, the Attorney General asserts that the Department must ensure that charges resulting from the operation of the TIRF are just and reasonable (Attorney General Brief at 56). The Attorney General adds that National Grid cannot seek to shelter investment decisions that yield unjust and unreasonable rates by claiming that it must be allowed the business judgment to select a particular capital replacement program and then ask the Department to review the cost recovery mechanism under standards other than those prescribed by G.L. c. 164, § 94 (Attorney General Brief at 56, citing New England Telephone and Telegraph v. Department of Public Utilities, 360 Mass. 443 (1971)). The Attorney General claims that the operation of National Grid's proposed TIRF will not result in just and reasonable rates as required by G.L. c. 164, § 94 (Attorney General Reply Brief at 13).

c. Flawed Empirical Support for National Grid's TIRF

The Attorney General claims that the empirical analysis used to support National Grid's targeted infrastructure replacement program is flawed (Attorney General Brief at 58-59; Attorney General Reply Brief at 13). The Attorney General criticizes National Grid's analysis comparing its historic leak and replacement activities to a peer group of comparable utilities to support its claim that National Grid's pipeline systems are old and lagging behind similarly-situated utilities and, therefore, in need of a special ratemaking mechanism to make up this deficit (Attorney General Brief at 58-59). The Attorney General argues that many of the peers chosen to establish performance benchmarks are smaller and have considerably lower shares and absolute amounts of leak-prone pipes and, therefore, such a comparative analysis fails to support National Grid assertions about the need for its proposed TIRF (Attorney General Brief at 59, 90).

Further, the Attorney General argues that while National Grid leak-prone mains and services are 50 to 100 years old, this condition did not arise overnight and there has been no catastrophic or overnight aging event that suddenly necessitates a 40 percent replacement rate for a select set of pipes over the next decade (Attorney General Brief at 59).

While National Grid's historic replacement of leak-prone pipe is lagging compared to its peers, the Attorney General argues that it has not resulted in leak rates that are so unusual that they would require a special type of ratemaking treatment such as the TIRF (Attorney General Brief at 89; Attorney General Reply Brief at 13). The Attorney General contends that the trends in leak rate per customer show that Essex Gas and Colonial Gas have tended to exhibit leak rates that are less than the peer average since as early as 2003 (Attorney General Brief at 59, citing Exh. AG-DED-1, Sch. DED-23). Specifically, the Attorney General argues that, relative to their peers, both Essex Gas and Colonial Gas have made significant progress in either containing or reducing leaks since 1990 and that their leak rates are half those of their 1990 levels, while the peer group leak rate average has increased twofold over the same time period from 1990 through 2008 (Attorney General Brief at 60, citing Exh. AG-DED-1, Sch. DED-22).[63] In addition, the Attorney General states that while Boston Gas shows historic leak rates per customer above the peer average for many years, those rates have become considerably more reasonable since 2007 and, therefore, National Grid's leak rate performance does not appear to have suffered over the past several years from its slower pipeline replacement activities or the age of its facilities (Attorney General Brief at 59).

The Attorney General claims that National Grid did not provide adequate explanation regarding the deficiency of its past replacement efforts and progress on reducing the average age of its bare steel and cast iron mains (Attorney General Brief at 59). According to the Attorney General, National Grid has acknowledged that, had it replaced more pipes in prior years, its current leak rate and average system age would be lower (Attorney General Brief at 59, citing Tr. 5, at 522). Further, the Attorney General argues that National Grid has not justified the necessity for it to be compensated to accelerate its replacement activities over the next decade when it "frittered away the opportunity to do so over the past decade" (Attorney General Brief at 60, citing Exh. AG-DED-1, Sch. DED-21).

The Attorney General argues that if National Grid were genuinely concerned about the age and integrity of its distribution pipeline system and its purported need for accelerated

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[63] The Attorney General claims that National Grid could not provide adequate explanation of why the leak rates of the Essex Gas and Colonial Gas systems are considerably lower than that of the Boston Gas system (Attorney General Brief at 60-61, citing RR-DPU-101, Att.; Tr. 8, at 2508). The Attorney General claims that National Grid's lack of understanding of what is actually driving leak and replacement activities and trends on its system underscores the lack of accountability under the current program and the challenge the Department is likely to face under a mechanism like the TIRF that will allow National Grid to increase its plant investment by over 40 percent in a relatively short period of time (Attorney General Brief at 61).

replacement, it was well within its ability to pursue activities comparable to those of other utilities (Attorney General Brief at 61). The Attorney General, however, claims that National Grid's rate of replacing pipe was negligible prior to 2000, increased somewhat from 2000 through 2002 before it slowed again considerably and, as of 2009, National Grid's replacement rate has not recovered to 2002 levels (Attorney General Brief at 61-62, citing Exhs. AG-CJM-1, Table CJM-2; AG-DED-1, Sch. DED-21).[64]

The Attorney General disputes National Grid's claim that the peer group of companies had replaced more pipes because they were given rate recovery opportunities not currently afforded to National Grid (Attorney General Brief at 62, citing Tr. 5, at 544). The Attorney General argues that only three of the 22 companies in National Grid's peer group of utilities currently have a pipe infrastructure cost recovery rider in place (Attorney General Brief at 62). Instead, the Attorney General claims that these peer gas companies acted prudently and replaced their leaking pipes on a much more accelerated basis than National Grid (Attorney General Brief at 62).

The Attorney General also disputes National Grid's claim that its anticipated O&M spending on a going forward basis will escalate if an aggressive replacement program is not put in place (Attorney General Brief at 62). The Attorney General asserts that the Department should reject this assertion as a basis for the TIRF (Attorney General Brief at 62). The Attorney General adds that ratepayers should not be required to automatically pay for an

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64 As further discussed below, the Attorney General claims that National Grid significantly decreased spending on pipe replacement since 2002, contributing to the current state of its distribution systems (Attorney General Brief at 68).

accelerated pipeline replacement program because National Grid failed to engage in the same replacement practices, at the same rate, as its natural gas distribution peers (Attorney General Brief at 62-63).

d. Measure of Leak Rates

The Attorney General questions National Grid's use of the leak rates in its distribution system to justify the proposed TIRF (Attorney General Brief at 63; Attorney General Reply Brief at 13). As one measure of leak rate, the Attorney General states that National Grid divides the leaks that occurred on the pipe in a given year by the corresponding inventory of pipe for that year. The Attorney General notes that this measure is flawed because National Grid carried a leak backlog from year to year and, therefore, it cannot equate the number of leaks fixed with the number of leaks that occurred in any given year (Attorney General Brief at 63, citing Exh. NG-WJA-1, at 11). Further, the Attorney General adds that this error is greatly compounded if leaks that were detected at an earlier time, when the miles of leak-prone mains were higher, are deferred to be fixed at a later date when fewer miles of leak-prone mains are in services due to ongoing main replacements activities (Attorney General Brief at 63).

The Attorney General also argues that National Grid divides the number of leaks eliminated or repaired for a given year by the corresponding pipe inventory as an alternate measure of leak rate (Attorney General Brief at 63). Noting that National Grid has claimed to have reduced leak backlogs in recent years, the Attorney General observes that using this second measure of leak rate would result in rising leak rates as main repair and replacement accelerate (Attorney General Brief at 64). Accordingly, the Attorney General recommends that the Department carefully consider whether the leak rates presented by National Grid accurately reflect the underlying health of its distribution mains (Attorney General Brief at 64).

The Attorney General also claims that National Grid inappropriately expanded its definition of leak-prone pipes to include pipes leaking as a result of corrosion, natural forces, and other causes (Attorney General Brief at 64-65). The Attorney General asserts that this expanded definition results in a measure of leaks that is 63 percent overstated (Attorney General Brief at 66, citing Exh. AG-7-4, Att.; Attorney General Reply Brief at 18-19).[65]

Finally, the Attorney General notes that National Grid's pipeline replacement data are inaccurate in some respects (Attorney General Brief at 66).[66] The Attorney General claims that these anomalies in National Grid's reported pipeline replacement data were never explained

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65 Specifically, given the inclement weather faced by National Grid relative to the 22 gas companies in its peer sample group, many of which are located in states with more temperate weather conditions, the Attorney General argues that National Grid should be expected to have more weather-related leaks than other utilities in the peer group (Attorney General Reply Brief at 17). Moreover, because National Grid's definition of natural forces includes leaks associated with natural disasters but does not provide an adjustment to correct for the fact that natural forces can be indiscriminate when it comes to pipe type, comparisons of leak rates without making adjustments for those differences would not be valid (Attorney General Reply Brief at 17-18).

66 For example, the Attorney General notes that National Grid's filing to the U.S. Department of Transportation, Office of Pipeline Safety ("OPS") suggested that a total of 755 miles of pipeline was replaced by Boston Gas, Essex Gas and Colonial Gas in 2001, which should have required an investment of $840 million with a replacement cost of $1.1 million per mile (Attorney General Brief at 66, citing Exh. AG-46-34). Further, according to the Attorney General, in 2001 National Grid reported a $114 million investment in main replacement, which includes not only replacements of leak-prone facilities but also expenditures related to growth and other repairs (Attorney General Brief at 66-67, citing Exh. AG-DED-1, at 86-87).

and, therefore, should raise further concerns by the Department in evaluating National Grid's likely reporting performance under an accelerated replacement mechanism like the TIRF (Attorney General Brief at 67).

e. National Grid's Decreased Spending Since 2002

The Attorney General refutes National Grid's claim that it consistently and significantly increased capital investment in leak-prone pipe replacement activities beginning in 2002 and increased its spending on leak-prone pipe replacement each year from 2002 through 2007 (Attorney General Brief at 68, citing Exhs. NG-JBH, at 23; AG-29-2). The Attorney General asserts that the record does not support this claim (Attorney General Brief at 68-69). Specifically, the Attorney General asserts that from 2002 through 2007, National Grid consistently decreased spending on leak-prone pipe replacement, noting that in 2003, National Grid spent approximately $37.9 million and, for each of the years from 2004 through 2007, National Grid spent less than $37.9 million on an inflation adjusted basis (Attorney General Brief at 68-69, citing Exhs. AG-7-7; AG-29-1). The Attorney General states that only in 2008 and 2009, with 2009 as the test year in this proceeding, did National Grid increase spending on TIRF-related projects over its 2003 spending level (Attorney General Brief at 69, citing Exh. AG-29-1).[67] According to the Attorney General, National Grid's witness conceded that it significantly reduced the miles of pipe replacement each year from 2002 through 2008 but then significantly increased its miles of pipe replacement in the test years for its two most recent

[67] The Attorney General also claims a similar trend in the corresponding number of miles of mains that National Grid replaced over the same time period (Attorney General Brief at 69, citing Exh. AG-10, as derived from Exh. AG-7-10).

base rate proceedings (i.e., 2002 and 2009) (Attorney General Brief at 69; Tr. 4, at 499). The Attorney General asserts that National Grid's historical spending on TIRF-related projects, rate of replacement of distribution mains, and its long-standing knowledge that substantial and consistent increases in spending were necessary to protect the safety and reliability of its system, leads to the conclusion that National Grid failed to incur the necessary expenses to make its system safe and reliable from 2003 through at least 2007 (Attorney General Brief at 69-70).

The Attorney General disputes National Grid's claim that its high pipe replacement level for 2002 is attributable to replacement activities associated with the "Big Dig" and represents a "high water" mark of replacement activity (Attorney General Reply Brief at 19 20, citing National Grid Brief at IV.25). The Attorney General argues that National Grid's witness could not identify the Big Dig as a source of high pipeline replacement activity (Attorney General Reply Brief at 20, citing Tr. 5, at. 517, 521-524).

In sum, the Attorney General asserts that the Companies' significant decrease in pipe-replacement projects from 2002 through 2008 contradicts their assertion that the current state of the Companies' system is a result of the age of their systems, and that the need for expedited recovery of pipe replacement costs is necessary despite their so-called "motivated . . . replacement activities" from 2002 through 2007 (Attorney General Brief at 71, citing Exh. NG-JBH, at 14-15). The Attorney General argues that had National Grid increased its pipeline replacement activities beginning in 2002, as opposed to significantly decreasing them, National Grid's systems would be in better shape today and National Grid would be experiencing lower leak rates and improved safety and reliability (Attorney General Brief at 71, citing Exh. AG-CJM-1, at 6-9).[68] Accordingly, the Attorney General argues that National Grid should not be granted expedited recovery of the costs of pipe replacement projects where the asserted need for such expedited recovery is due in large part to the Companies' own conduct in allowing a significant decrease in pipe replacement from 2002 through 2007 (Attorney General Brief at 72).

f. Leak Rate Performance Measure

The Attorney General contends that National Grid has chosen the wrong leak rate per total miles of mains as a performance measure to benchmark its performance under the proposed TIRF (Attorney General Brief at 72; citing Exh. NG-JBH-1, at 28). The Attorney General explains that the use of a measure based upon leak reductions per total mile of pipe could lead to unanticipated consequences and skews performance measures (Attorney General Brief at 72, citing Exh. AG-DED-1, at 97; Attorney General Reply Brief at 21). For example, the Attorney General notes that under National Grid's leak rate proposal, the target could be met by simply installing more miles of additional new pipe and not by replacing leak-prone pipe (Attorney General Brief at 72, citing Exh. AG-DED-1, at 83).[69]

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68 The Attorney General claims that, had National Grid escalated its replacement rate since 2002 by just 2.5 percent per year, it would currently have 267 miles less of target pipe in the ground (Attorney General Brief at 71 n.26, citing Exh. AG-CJM-1, at 5-9).

69 The Attorney General notes that under National Grid's capital expenditure proposal, 20 percent of the total anticipated investments are for growth-related projects that could potentially skew performance measures that are based on leaks per total miles of pipes and fail to directly address the problem of leaks on leak-prone pipes (Attorney General Brief at 73, citing Exh. NG-JBH-3; Attorney General Reply Brief at 21).

In addition, the Attorney General contends that National Grid's use of a performance measure of 0.32 average leak per total mile based on the average leak rate of a peer group of 22 gas distribution companies is problematic because none of those peer companies have close to the proportion of cast iron and wrought iron pipes that National Grid has (i.e., 22 percent) and, therefore, this benchmark is arbitrarily low (Attorney General Brief at 73-74). To demonstrate her point, the Attorney General divided the 22 peer companies into two groups: (1) companies with greater than or equal to 40 percent unprotected steel, cast iron, and wrought iron mains; and (2) companies with less than 40 percent unprotected steel, cast iron, and wrought iron mains (Attorney General Brief at 75). The Attorney General determined a leak rate of 0.536 leak per leak-prone mile of pipe for the first group and 0.160 leak per leak-prone mile for the second group (Attorney General Brief at 75, citing Exh. AG-7-4).

If the Department approves National Grid's proposed TIRF, the Attorney General argues that its goal should instead be 0.536 leaks per mile of leak-prone pipes, which she contends could be achieved well within ten years (Attorney General Brief at 76). The Attorney General recommends that National Grid be required to demonstrate what level of investment would be required in order to achieve a 0.536 aggregate leak rate per leak-prone miles over the next five years (Attorney General Brief at 76).[70]

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[70] The Attorney General disagrees with National Grid's position, which suggests that a ten-year term for the proposed TIRF is necessary in order to create the regulatory certainty needed to enter into contracts with internal and external labor necessary to ensure that projects are cost effective. She notes that: (1) long-term contracts are simply a type of cost hedging or insurance mechanism that provides National Grid with long-term input cost certainty; (2) insurance does not come free and nowhere has National Grid demonstrated that it would be prudent or necessary to enter into these

The Attorney General states that approving a five year TIRF instead of the ten-year TIRF sought by the Companies would still allow National Grid to achieve the contracting efficiencies where contractors have indicated to National Grid that a minimum five-year commitment is needed to provide the financial security for contractors to hire and train qualified workers and equip those workers to complete National Grid's main replacement projects (Attorney General Brief at 76, citing Exh. NG-JBH at 17).

Accordingly, the Attorney General recommends that, if the Department approves National Grid proposed TIRF, the mechanism should have a five year term and the performance benchmark should be based upon the number of leaks per leak-prone miles of pipe, where leak-prone pipes consist of unprotected steel and small diameter cast iron and wrought iron mains (Attorney General Brief at 76; Attorney General Reply Brief at 20). The Attorney General claims that using this measure captures the real issue at hand, which is the replacement of the pipes most likely to result in leaks and not total pipes (Attorney General Brief at 76; Attorney General Reply Brief at 20). The Attorney General adds that the policy goal for adopting the TIRF should be leak reduction, not load building or rate base building (Attorney General Brief at 77).

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types of arrangements; and (3) National Grid has not provided any information on the duration of these contracts and which party will bear the risk of covering the costs of long-term contracting if material or wage costs fall below the long-term contracted amount (Attorney General Reply Brief at 16, citing National Grid Brief at IV.20).

g. Incremental Costs and TIRF Recovery

The Attorney General notes that the proposed TIRF mechanism is intended to recover the incremental costs to support the investments under National Grid's targeted infrastructure replacement program (Attorney General Brief at 85, citing Tr. 3, at 188). However, the Attorney General claims that National Grid has neither offered a consistent definition of incremental costs nor developed a method for tracking those costs (Attorney General Brief at 85, citing Tr. 3, at 191-201).

The Attorney General states that the problem with a vague delineation of what is or is not an incremental cost stems from how those costs relate to the cost of service (Attorney General Brief at 85). The Attorney General claims that National Grid has not demonstrated that, in practice, its proposed TIRF will collect costs only once, noting that the Department and the Supreme Judicial Court have rejected the double collection of costs from customers (Attorney General Brief at 86).

The Attorney General asserts that National Grid should not presume that, if work is done on the TIRF-related projects, it automatically increases costs to National Grid because it assumes that National Grid's work forces are 100 percent utilized at all times, an assumption that the Attorney General claims National Grid acknowledges is not reasonable (Attorney General Brief at 87, citing Tr. 10, at 1444-1445). The Attorney General asserts that incremental costs should have a specific, fixed, and transparent definition for ratemaking purposes (Attorney General Brief at 88). The Attorney General recommends that if the Department approves the TIRF recovery mechanism, the following definition of incremental costs should be applied for ratemaking purposes and the language inserted into National Grid's tariff that seeks to collect incremental TIRF costs: "Incremental costs shall mean only those costs directly and completely incurred by, and necessary for, TIRF reliability projects. Incremental costs shall exclude any direct, indirect, assigned or allocated costs recoverable or represented in whole or in part in any other rate, charge or tariff" (Attorney General Brief at 88).

In addition, the Attorney General recommends that the Department should: (1) require National Grid to file, as part of any compliance filing and for each annual filing associated with any incremental cost recovery, National Grid's actual accounting manual, amendments, standards, guidance or interpretation related to the definition and classification of costs as "incremental;" (2) require National Grid to modify its work order management system in order to code, track, and distinguish between incremental TIRF reliability activities and all other types of company projects; (3) condition approval of any TIRF recovery mechanism on National Grid's internal auditors' examining the program for compliance, including examination of National Grid's determination of incremental and non-incremental program costs; and (4) require the results of this internal audit to be submitted with each filing that requests a rate increase associated with the TIRF (Attorney General Brief at 88-89).

h. Worst-First Basis Sequence of Pipe Replacement

The Attorney General recommends that regardless of whether or not the Department approves National Grid's proposed TIRF, the Department should require National Grid to replace the bare steel and small diameter cast iron on a "worst-first" basis (i.e., to replace mains and services that are most immediately in need of replacement, rather than on an ad hoc basis or one that is simply determined by material type) (Attorney General Reply Brief at 23). The Attorney General claims that such an approach would result in a more expeditious decrease in National Grid's overall leak rate, which is one of the primary goals of its proposed TIRF (Attorney General Reply Brief at 23, citing Exh. NG-JBH-1, at 28).

The Attorney General claims that National Grid has provided no evidence demonstrating that it will replace bare steel and small diameter cast iron on a worst-first basis for the plant additions proposed in this case (Attorney General Reply Brief at 23, citing Exh. NH-AS-2). Accordingly, the Attorney General contends that the Companies cannot demonstrate that they will engage in a prudent, reasonable and economic incurrence of costs in a replacement program that attempts to minimize the overall costs of mains and service replacements (Attorney General Reply Brief at 23).

i. Separate TIRFs for Companies and Limits on TIRF Program

The Attorney General recommends that, should the Department allow National Grid to implement a TIRF, the Department should adopt the following limits to protect customers. First, she recommends that the TIRF for the three National Grid Massachusetts companies should not be combined and each service territory should be responsible for its own capital improvements, replacements and expansion (Attorney General Reply Brief at 22). The Attorney General argues that each system has different capital needs and customers should not be forced to subsidize the needs of other service territories (Attorney General Reply Brief at 22). Second, the Attorney General recommends that the Department limit the amount collectable from customers through the TIRF to deter excessive investment and simultaneously establish a floor level of activity with objective measures like minimum levels of pipe replacement per year, as opposed to a simple dollar threshold, to provide some protection against National Grid's switching to high cost but low levels of replaced materials (Attorney General Reply Brief at 22). The Attorney General recommends that, should the Department adopt this recommendation, it should open a brief proceeding to set the appropriate limits and thresholds for the targeted infrastructure replacement program (Attorney General Reply Brief at 23).

j. O&M Offsets by Service Territory

The Attorney General claims that the Companies incorrectly calculated the proposed O&M offset, providing results that are more favorable to National Grid (Attorney General Brief at 82). More specifically, the Attorney General notes that in calculating the proposed O&M offset, National Grid multiplied the 2009 average cost to repair a leak by the 2008 average leaks per mile of mains, which is equal to 1.42 leaks per mile, instead of using the 2009 average leaks per mile equal to 1.77 (Attorney General Brief at 82, citing Exhs. DPU-6-8; AG-7-9).

The Attorney General notes that National Grid has conceded that consistent data should be used in the calculations (Attorney General Brief at 82-83, citing Tr. 5, at 564). The Attorney General recommends that, if the Department allows the TIRF, it should direct National Grid to recalculate the O&M offsets by service territory and material, as reflected in

Attachment Exhibit AG-7-9, using an average leak per mile of 1.77, rather than 1.42 (Attorney General Brief at 83).

k. Cost of Capital in the TIRF Mechanism

The Attorney General notes that the levels of investment under National Grid's proposed TIRF are a significant departure from the levels that it has spent historically on its replacement of its mains and services (Attorney General Brief at 83, citing Exh. AG-TN, at 13-15). The Attorney General argues that National Grid has not explained how it can claim that it has operated a system that has been safe and reliable under its historical levels of mains and service replacement, yet now needs to more than triple its annual investment in order to maintain that same level of safety and reliability (Attorney General Brief at 83, citing Exh. AG-TN, at 13-15).

The Attorney General argues that either: (1) National Grid, contrary to its claims in the past, did not maintain a safe and reliable system during the last 13 years when it was under its PBR rate plans; or (2) National Grid's professed need in this case to immediately replace all of its small diameter bare steel and cast iron mains and services is nothing more than a construct to artificially boost its earnings (Attorney General Brief at 71, 83, citing Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 231 (2002); Exh. AG-TN, at 13-15). The Attorney General adds that, in either case, National Grid's shareholders will be unfairly enriched if the TIRF is approved (Attorney General Brief at 83, citing Exh. AG-TN, at 13-15).

The Attorney General reasons that if National Grid failed to maintain a safe and reliable system in the past by deferring investment in mains and services, then shareholders received higher earnings than they should have under the PBR rate plans and the Department should reduce the ROE on all of National Grid's rate base to reflect such imprudence (Attorney General Brief at 83-84, citing Exh. AG-TN, at 13-15). On the other hand, the Attorney General adds that if National Grid has a system that is the safest that is has ever been, then there is no need to accelerate system replacement as proposed (Attorney General Brief at 84, citing Exh. AG-TN, at 13-15). The Attorney General states that on this basis the Department should reject the proposed TIRF mechanism (Attorney General Brief at 84, citing Exh. AG-TN, at 13-15).

However, the Attorney General argues that if the Department approves the TIRF, it should insure that National Grid's shareholders are not unfairly enriched for TIRF investments at the expense of its customers (Attorney General Brief at 83-84, citing Exh. AG-TN, at 13-15). Accordingly, in order to balance shareholders' and customers' interests, the Attorney General recommends that the Department reduce National Grid's ROE included in the cost of capital calculations for the TIRF to a level that reflects the rate for long-term A-rated utility bonds (Attorney General Brief at 84, citing Exh. AG-TN, at 16).

The Attorney General argues that National Grid's claim that the market will react negatively if the Department applies a lower rate of return to projects included in the TIRF is unsupported by record evidence (Attorney General Reply Brief at 21). The Attorney General adds that it is unlikely that markets would react negatively to a lower rate of return on these investments because the return of and on investment would occur without any required rate case, which is something that investors would see as exceptionally beneficial when compared to having to wait until the next rate case in order to attain a return on and of any capital investment (Attorney General Reply Brief at 21-22). The Attorney General contends that a lower return cannot be interpreted as a departure from traditional regulatory principles or as any form of "taking" because the reduction reflects the lower risk and, therefore, the lower required cost of capital (Attorney General Reply Brief at 21-22).

2. DOER

a. Accelerated Pipe Replacement Should be Supported by the TIRF

DOER recommends that National Grid accelerate the replacement of unprotected steel and small diameter cast iron mains and be permitted to recover the capital cost through a TIRF mechanism (DOER Brief at 8). DOER argues that it is generally accepted in the natural gas industry that unprotected bare steel and small diameter cast iron pipes are leak-prone by current standards and that it is highly desirable to replace these materials with more modern material (DOER Brief at 8).

DOER notes that 36 percent of National Grid's distribution system consists of relatively higher risk leak-prone material and 60 percent of Boston Gas' system alone is comprised of leak-prone pipe (DOER Brief at 8). DOER estimates that, at the current rate of replacement, it would take over 60 years to replace these leak-prone facilities, while they continue to deteriorate, resulting in increasing costs and increased risk to customers (DOER Brief at 8).[71] DOER argues that National Grid has presented ample evidence that its system warrants the accelerated replacement of leak-prone pipe (DOER Brief at 8).

71 DOER observes that based on 2008 data, 93 percent of National Grid's leak repairs were made to its leak-prone pipes (DOER Brief at 8).

b. Carrying Charge Due to the Billing Delay

Regarding the carrying charge component of National Grid's proposed TIRF, DOER recommends that National Grid be permitted to recover carrying costs on these amounts until such time as it begins to recover costs through the TIRF, but not at its pre-tax WACC (DOER Brief at 9). DOER claims that National Grid did not address the basis for using the pre-tax WACC to represent National Grid's short-term carrying costs (DOER Brief at 9, citing Exhs. NG-NS-1, at 26; NG-MDL-1, at 86).

DOER reasons that, given the significantly higher level of capital investment required for National Grid's targeted infrastructure replacement program as compared to Bay State's program, National Grid should not have a financial disincentive to make necessary and timely TIRF-related investments (DOER Brief at 9). DOER contends that National Grid should be able to recover its actual carrying costs associated with the ten-month billing delay but that those carrying costs should be based on National Grid's actual short-term borrowing costs and not on its pre-tax WACC (DOER Brief at 9).

DOER notes that National Grid has proposed significantly lower carrying costs on TIRF revenue requirement deferrals (DOER Brief at 9, citing RR-DPU-56). DOER notes that the delay of recovery of those costs would be at least an additional twelve months because the earliest that the deferral could be recovered would be November 1 of the following year (DOER Brief at 9). Accordingly, DOER concludes that using National Grid's actual short term debt expense as its carrying costs for TIRF-related investments is appropriate (DOER Brief at 9).

c. Cap on the Annual TIRF Revenue Requirement

DOER recommends that the Department adopt National Grid's proposed fixed cap but limit the annual cap on recovery of TIRF-related investments to two percent (DOER Brief at 10). DOER explains that National Grid's gas distribution system is comprised of significantly more leak-prone pipes than that of Bay State, such that this difference warrants a higher cap on National Grid's TIRF than the Department approved for Bay State (DOER Brief at 10-11). DOER reasons that a two percent cap is a compromise between National Grid's proposal and the cap set for Bay State in D.P.U. 09-30 (DOER Brief at 10-11). DOER claims that two percent is a more reasonable cap and should help to mitigate the potential rate impacts of National Grid's TIRF proposal over the long term (DOER Brief at 11). DOER also argues that combining these caps with a reasonable, cost-based carrying charge as discussed above for deferred recovery of TIRF-related investments, would enable National Grid to make the necessary replacements without significantly impacting its earnings (DOER Brief at 11).

d. Ratemaking Treatment of Depreciation, Overhead and Burden Costs

In regard to the treatment of depreciation, labor overhead, and burden costs associated with TIRF-related investments, DOER recommends that the Department adopt National Grid's proposed modifications and clarifications (DOER Brief at 12). In particular, DOER recommends that the Department adopt National Grid's proposed three-step process to ensure that it not recover those costs twice (i.e., through base rates as an O&M expense and again through the TIRF (DOER Brief at 12). DOER argues that National Grid's proposal adequately insures that only incremental costs associated with TIRF-related investments, and not already included in base rates will be recoverable through the TIRF (DOER Brief at 12).

3. TEN

a. Introduction

TEN urges the Department to make the following changes to National Grid's proposed TIRF: (1) recover TIRF costs from rate classes using a rate base allocator; (2) deny the carrying charge; (3) use a two percent cap on annual TIRF revenue requirement, instead of the proposed three percent cap; and (4) extend the term of the program from ten to 15 years (TEN Brief at 9-13).[72] These four suggested changes are described below.

b. Rate Base Allocator to Recover TIRF Revenue Requirements

Regarding its proposed rate base allocator, TEN claims that National Grid's proposal to collect TIRF costs on a company-wide per therm unit charge is inappropriate because such a method fails to properly allocate among rate classes the costs and benefits on a cost of service basis (TEN Brief at 9; TEN Reply Brief at 7). TEN argues that the TIRF costs must be collected on the same basis as distribution costs to correctly charge distribution ratepayers their appropriate costs for system improvement (TEN Brief at 9). Accordingly, TEN recommends that the Department adopt a cost recovery rate structure for the TIRF based on a rate base allocator (TEN Brief at 10). TEN claims that National Grid has indicated that: (1) it can implement such a recovery mechanism; (2) that it is indifferent to the cost recovery

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[72] TEN also expressed concerns about the potential for recovering overhead and burden costs twice (TEN Brief at 12). TEN states that National Grid has offered solutions that the Department should adopt to protect ratepayers (TEN Brief at 12, citing RR-DPU-107, at 1; TEN Reply Brief at 10, citing National Grid Brief at 18-20).

mechanism; and (3) a more appropriate mechanism would not use a volumetric approach (TEN Brief at 9, citing RR-TEN-4 (b); Tr. 3, at 212-213; TEN Reply Brief at 8).

c. Carrying Charge Due to the Billing Delay

TEN claims that the absence of a carrying charge and the provisions of a one percent cap are at the heart of the specific limitations that supported the Department's decision to approve a TIRF for Bay State in D.P.U. 09-30 (TEN Brief at 5-6, 8). Accordingly, TEN suggests that the Department should follow its precedent established in D.P.U. 09-30 and deny National Grid's proposal for a carrying charge on the TIRF billing delay (TEN Brief at 10; TEN Reply Brief at 9).

d. Cap on the Annual TIRF Revenue Requirements

Regarding the cap on the annual TIRF revenue requirement, TEN urges the Department to impose a two and one-half percent cap instead of the three percent cap proposed by National Grid (TEN Reply Brief at 8-9). TEN explains that, although it initially recommended a two percent cap, National Grid offered persuasive arguments on brief that 2.5 percent would be needed to achieve its program goals over a 15-year term (TEN Reply Brief at 8-9; see TEN Brief at 10-11). TEN states that this recommendation is consistent with its proposal, as discussed below, to extend the term of the TIRF program to 15 years (TEN Reply Brief at 9). TEN argues that its proposal strikes a balance that is fair to ratepayers and National Grid while at the same time meaningful in the context of safety and reliability (TEN Reply Brief at 9).[73]

[73] TEN claims that a three percent cap provides National Grid with the ability to spend approximately $40 million per year on the TIRF revenue requirement (TEN Brief

e. Term of the TIRF Mechanism

TEN notes that Bay State's targeted infrastructure placement program is projected to require 10-15 years to complete as compared to National Grid's proposed ten-year program (TEN Brief at 8, citing D.P.U. 09-30, at 118-121).[74] TEN argues that, except for Colonial Gas (Cape Cod), the individual Companies experience below peer average system gas losses, which suggests that, notwithstanding National Grid's data on leak-prone pipes and the age of pipe, those Companies, on average, have tight systems (TEN Brief at 8-9, citing RR-TEN-2, at 1-2). TEN argues that such tight systems, combined with the testimony by National Grid that its system has been, remains, and will continue to be safe and reliable, suggest that the speed of replacement offered by National Grid is unnecessarily swift and, as a consequence, imposes costs on ratepayers too aggressively (TEN Brief at 9).

Accordingly, TEN suggests that the Department require National Grid to extend its targeted infrastructure replacement program from ten to 15 years (TEN Brief at 12). TEN contends that the TIRF mechanism, together with the rate increase and other fully reconciling cost recovery mechanisms likely to be approved in this case, places a heavy burden on distribution customers (TEN Brief at 12). TEN argues that extending the period for the TIRF program is a way to mitigate such burden on customers (TEN Brief at 12).

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at 11). TEN notes that National Grid's proposed three percent cap potentially increases the Companies' total revenue increase starting in 2012 by 40 percent (TEN Brief at 11).

74 TEN states that National Grid's TIRF, as proposed, is more akin to a local economic stimulus project to create 400 jobs in Massachusetts (TEN Brief at 9, citing Exh. NG-NS-1, at 30, line 2).

4. NEGWA

NEGWA recommends that the Department reject National Grid's proposed TIRF and, instead, require National Grid to develop a reasonable pipe replacement program, including a program for cathodic protection of all unprotected steel (NEGWA Brief at 21). NEGWA contends that National Grid's proposed accelerated replacement of leak-prone mains and services to be supported by the TIRF is wasteful because it will replace serviceable pipe at greater cost than other alternatives (NEGWA Brief at 14, 21, citing Exh. NG-NS-1, at 7).[75] In addition, NEGWA claims that National Grid's professed need for accelerated pipe replacement is inflated by its backlog volume of longstanding Class 3 leaks (i.e., the least serious class of leaks), claiming that such leaks account for 92.4 percent of all outstanding leaks (NEGWA Brief at 14, citing Exh. NEGWA-3, RR-DPU-114; Tr. 20, at 2855). NEGWA observes that National Grid's level of Class 1 and 2 leaks, which are the most serious grades of leaks, is currently at the lowest point since 1990 (NEGWA Brief at 16, citing Exh. NEGWA-5). NEGWA adds that National Grid conceded the good condition of its system, despite the absence of a TIRF, when its executive vice-president for gas distribution told the public that "National Grid's system is in the best shape that it's ever been" (NEGWA Brief at 16, citing Exh. NEGWA-MM-1, at 8; Tr. 20, at 2856).

In addition, NEGWA claims that National Grid's 2008 overall report of leaks repaired appears to be based on considerable duplications, noting that it has identified 1,648 duplicate

75 NEGWA expressed concerns about the dangers of using plastic mains (NEGWA Brief at 3-5). In addition, NEGWA argues that it costs National Grid 6.7 times more to use outside contractors for such work as compared to the cost of using permanent employees (NGWA Brief at 1).

entries for bare steel and cast iron leak repairs (NEGWA Brief at 16, citing Exh. NEGWA-2-162b). NEGWA argues that correcting for duplication and the backlog of longstanding unrepaired leaks, the new estimate of leaks per mile of pipe is not as high as National Grid claims (NEGWA Brief at 16).

NEGWA also argues that, while National Grid has managed to keep up with current replacement needs in its Colonial Gas and Essex Gas service areas, it has not done so for its Boston Gas service area (NEGWA Brief at 17-18).[76] NEGWA contends that the high level of Class 3 backlog for Boston Gas is "due to foot-dragging at best" and National Grid should not be rewarded for such behavior with a TIRF (NEGWA Brief at 17-18).[77] NEGWA claims that the gas lost due to leaks was more than 1.1 billion cubic feet, valued at $11.7 million and representing almost one third of National Grid's leak repair budget of $36.5 million (NEGWA Brief at 18, citing Exh. AG-39-10). NEGWA contends that, not even considering the environmental impact of this amount of gas leaked to the atmosphere, a more vigorous repair effort would save this cost of lost gas as well as the cost of multiple annual re-inspections (NEGWA Brief at 18).

NEGWA claims that National Grid's TIRF proposal is not based on economics but rather relies on a hastily conceived risk analysis that compares National Grid's unreliable leak

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[76] NEGWA observes that as of September 2007, the leak rates of National Grid's operating divisions were: 0.1 to 0.5 leak per mile for Colonial Gas; 0.5 leak per mile for Essex Gas, and 1.3 to 3.6 leaks per mile for Boston Gas (NEGWA Brief at 17, citing Exh. NEGWA-MM-1, at 8-9).

[77] NEGWA states that this delay, in turn, has caused extra costs because replacement costs are now $150 per foot compared to $94 per foot in 2002 (NEGWA Brief at 18, citing RR-NEGWA-18).

rates with inappropriate industry averages (NEGWA Brief at 18, citing Tr. 18, at 2509-2511). NEGWA contends that although National Grid's leak problem has been known since at least 2004 and has existed since at least 2000, National Grid did not perform this risk analysis until after the Department's Order in D.P.U. 09-30 in order to use such information to its financial advantage (NEGWA Brief at 18, citing Tr. 18, at 2511, 2515; Exhs. NEGWA-5, at 3; NG-NG-NS-1, at 4).

NEGWA states that despite National Grid's assertion that its replacement activities increased since 2003, this is not true for 2004 through 2007 when replacement spending stayed within the $30 million to $42 million range (NEGWA Brief at 18). NEGWA claims that it was only when National Grid started to prepare for its 2009 test year in the instant case that its spending increased to $61 million in 2008 and $96 million in 2009 (NEGWA Brief at 18, citing Exh.NG-JBH-2).

NEGWA also questions National Grid's decision to include non-corroded pipe in its definition of pipes that are leak-prone. Instead, NEGWA argues that non-corroded pipe only needs cathodic protection and monitoring (NEGWA Brief at 19, citing Exh. NG-NEGWA-37). NEGWA claims that cathodically protecting serviceable steel pipe would cost much less than replacing such pipe with plastic (NEGWA Brief at 19, citing Exh. NEGWA-1-37). Noting that National Grid plans to cathodically protect less than one third of its 1,800 to 1,900 miles of unprotected pipes, NEGWA claims that National Grid inappropriately persists in advancing its costly proposal to replace protectable, serviceable steel pipe (NEGWA Brief at 19, citing Tr. 4, at 369).

5. National Grid

a. Introduction

National Grid contends that there are two elements involved in the Department's consideration of its TIRF: (1) whether the public interest would be served by the establishment of a targeted funding mechanism to support a more aggressive pace for the replacement of leak-prone mains and services on National Grid's Massachusetts gas distribution system; and (2) if so, whether the proposed TIRF mechanism is reasonably designed to achieve the public interest goals (National Grid Reply Brief at 27).[78] National Grid claims that it performs all the necessary steps to maintain a safe distribution system (National Grid Reply Brief at 30). However, National Grid argues that, as a natural gas distribution company subject to state and federal pipeline safety requirements and with complete familiarity with the condition and risks of the infrastructure it operates, its best judgment is that an aggressive pace of replacement is needed to reduce the overall risk of the distribution system (National Grid Reply Brief at 30). National Grid claims that critical public safety goals cannot be consistently achieved or maintained without funding through a TIRF (National Grid Reply Brief at 30). Further, National Grid claims that the Department has recognized that a TIRF is likely to provide an incentive for more aggressive replacement of aging infrastructure (National Grid Reply Brief at 31, citing D.P.U. 09-30, at 132-133).

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[78] National Grid notes that by statute, the Department's core obligation is to protect the safety and reliability of gas and electric service and that the Department's decisions over the past 20 years have affirmed this obligation (National Grid Reply Brief at 28-29, citing G.L. c. 164, § 76; D.T.E. 05-27, at 38-39 (2005)).

National Grid contends that the policy determination in D.P.U. 09-30 that a TIRF is an appropriate rate recovery mechanism to address the accelerated replacement of aging infrastructure applies equally to it in this case (National Grid Brief at IV.8).[79] Accordingly, National Grid asserts that the only issues before the Department in this proceeding relate to the scope, pace, cost calculations, reporting requirements and similar details of its proposed TIRF and that the Department should not consider denial of National Grid's TIRF proposal as the Attorney General suggests (National Grid Brief at IV.8).

b. Empirical Support for TIRF Program and Measures of Leak Rates

Regarding the Attorney General's claim that the proposed TIRF should be rejected because National Grid does not have a documented infrastructure replacement program and that it has not conducted corrosion studies and root cause analyses in its distribution system, National Grid asserts that this claim ignores industry experience and generally accepted engineering and operating practice (National Grid Brief at IV.21). National Grid argues that the industry is well-aware that corrosion, age, and the environment are the primary causal factors for failure of unprotected steel pipe and, therefore, there is no need for such a study or

[79] National Grid claims that beginning in 1994, the Department implemented incentive-based ratemaking designed to achieve more efficient utility operations and cost control, and also the facilitation of mergers and acquisitions to achieve operational efficiencies through industry consolidation (National Grid Brief IV at 1, citing Incentive Regulation, D.P.U. 94-158 at 40 (1994); Mergers and Acquisitions, D.P.U. 93-167-A at 5-6 (1994)). National Grid also claims that today, aside from the pressure of increasing O&M expense, there is a need for capital investment well beyond the level that can be supported by growth in natural gas throughput in light of decreasing use per customer and the promotion of energy efficiency and implementation of revenue decoupling mechanisms (National Grid Brief at IV.2).

root cause analysis in order to make this determination (National Grid Brief at IV.21, citing Exh. NG-JBH-1, at 38-40).

National Grid explains that it is accepted industry knowledge that, where corrosion occurs as a result of environmental factors, the deterioration of the asset will increase exponentially until it reaches the end of its useful life, unless the environmental factors are changed (National Grid Brief at IV.5 n.3, citing Exh. DPU-6-28). National Grid adds that the condition of the pipeline segment will never remain stable or improve and that it is well recognized in the gas industry that smaller diameter cast iron pipe has thinner walls and lower beam strength and is many times more likely to break than larger diameter cast iron pipe (National Grid Brief at IV.22). National Grid argues that cast iron breaks are most commonly caused by natural forces from freeze-thaw cycles or undermining of sections of the pipe (National Grid Brief at IV.22). Accordingly, National Grid concludes that there is no empirical study that is necessary or warranted to determine that non-cathodically protected steel and small diameter cast iron mains should be removed from the system to reduce the potential for leaks (National Grid Brief at IV.22).

National Grid claims that the Attorney General provided no evidentiary basis for her assertion that because repaired leaks are not out of line with similarly situated gas utilities, National Grid's proposed TIRF should be rejected (National Grid Reply Brief at 35). National Grid contends that the Department's policy decision regarding the implementation of a TIRF mechanism is properly based on the circumstances existing on the distribution systems under the Department's jurisdiction (National Grid Reply Brief at 35-36, citing D.P.U. 09-30, at 129-135, 144-145). National Grid argues that (1) a significant portion of its system is composed of unprotected steel and small diameter cast iron and wrought iron mains and services; (2) there is a high probability of these facilities experiencing leaks due to corrosion, joint leaks and breakage; and (3) these facilities are responsible for over 90 percent of the leaks repaired annually on its distribution system (National Grid Reply Brief at 33, 36). National Grid adds that the existence of these leaks supports approval of the proposed TIRF in order to protect the public safety (National Grid Reply Brief at 36).

National Grid disputes the Attorney General's claim that it has exaggerated the apparent leaks from corrosion (National Grid Brief at IV.23, citing Attorney General Brief at 64-67, RR-DPU-101, RR-DPU-111; National Grid Reply Brief at 36). National Grid observes that the Attorney General excluded in her analysis the number of leaks recorded under the category of "natural forces," which resulted in her erroneous claim that National Grid's leak rate is overstated by 63 percent (National Grid Brief at IV.24).

National Grid explains that the natural forces category of leaks, as recorded in the annual U.S. Department of Transportation ("USDOT") report, is the category that is used throughout the gas industry to track leaks on cast iron facilities (National Grid Brief at IV.23). National Grid explains that the leaks that occur on these facilities do not occur as a result of corrosion but rather as a result of vibration, frost, or other environmental factors that affect the brittle and mechanically joined cast iron main facilities significantly more than any other materials (National Grid Brief at IV.23-24). National Grid claims that nearly 90 percent of the natural forces main leaks that occur in a year are on cast iron facilities, which is even greater than the leak rate for unprotected steel (National Grid Brief at IV.24; National Grid Reply Brief at 36-37, citing Exhs. NG-JBH-1, at 39-44; DPU-6-27; Tr. 4, at 477-489). National Grid argues that because the risk inherent in a gas distribution system is a function of the existence of facilities that have the potential to leak, that risk level is not correctly measured where the leaks associated with leak-prone inventory such as cast iron facilities are excluded from the leak-measurement analysis (National Grid Reply Brief at 40-41).

Regarding the Attorney General's assertion that National Grid has improperly relied on the leak repair rate rather than the rate of leak occurrence, National Grid contends that the rate of leak occurrence is not a valid indicator of the need for replacement of leak-prone infrastructure because this leak rate includes non-hazardous leaks or Class 3 leaks, which are not required to be repaired under the Department's pipeline safety and engineering standards (National Grid Brief at IV.22, citing Exh. NG-WJA-1). National Grid adds that unrepaired leaks cannot be accurately attributed to a specific main or service facility material or size because, by definition, the leaking pipe segment has not been uncovered but rather is monitored from the surface (National Grid Brief at IV.22-23).

National Grid claims that leak repair rates, defined as the number of leak repairs per mile, are a standard performance metric applied consistently throughout the gas industry for specific facilities and materials (National Grid Brief at IV.23). In addition, National Grid claims that it is standard industry practice to calculate leak repair rates using year-end inventories, including any backlogs that may be included in those numbers (National Grid Brief at IV.23).

Regarding the Attorney General's suggestion that the leak rate can be manipulated by including backlog repairs and then using the lower year-end leak-prone pipe inventory to inflate the leak rate, National Grid contends this claim is incorrect because of the significant inventory of leak-prone pipe on National Grid's system (National Grid Brief at IV.23). National Grid explains that historically it has replaced less than one percent of the total inventory of leak-prone mains in most years such that using the year-end inventory of a later year impacts the leak-prone pipe leak rates by about 1/100th of a leak, which is an inconsequential amount in terms of the overall calculation (National Grid Brief at IV.23).

c. Historical Leak Repairs

National Grid claims that there is no evidence to support the Attorney General's proposition that National Grid has historically replaced a smaller number of miles of leak-prone mains than it should have (National Grid Reply Brief at 34, citing Attorney General Reply Brief at 12-13). National Grid argues that many factors determine the optimal levels of replacement given system requirements, the opportunities and balance of repair and replacement activities, and the amount of available capital (National Grid Reply Brief at 34-35). National Grid claims that the trend in its TIRF-related replacements is demonstrated through annual TIRF-related spending totals which show that, in the period 1995 through 2009, National Grid's annual spending on TIRF-related investments increased from approximately $20 million to approximately $68 million, more than a 300 percent increase over a 15-year period (National Grid Reply Brief at 35, citing RR-AG-19).

National Grid also notes that while Boston Gas completed a substantial amount of pipeline replacement work for the Big Dig project in 2002, a more appropriate longer term view shows that capital spending has increased consistently over the period from 1995 to 2009 in accordance with the demands of the system (National Grid Brief at IV.25, citing RR-AG-19).

d. Leak Rate Performance Measure

National Grid explains that an analysis that uses only the category of corrosion related leaks as the measurement of leaks per leak-prone pipe, as the Attorney General suggests, is invalid because the population of leak-prone pipe includes small diameter cast iron which experiences a significant number of leaks annually and is reported under the natural forces category of leaks rather than the corrosion related category of leaks (National Grid Reply Brief at 47). National Grid explains that if it were only to include corrosion related leaks in the number of leaks on leak-prone mains, the only conclusion that the Department would be able to draw from this metric is relative to the leak rate on the unprotected steel mains remaining in the ground. National Grid argues that such a metric would not provide the Department with any indication of the improvement resulting from the elimination of small diameter cast iron mains, which is a significant element of National Grid's proposed targeted infrastructure replacement program (National Grid Reply Brief at 47-48).

National Grid states that while it will report the metrics that the Department prefers, it argues that the success of the targeted infrastructure replacement program in reducing the leak rate will not reasonably be measured using the Attorney General's proposed metric, which is flawed by virtue of the omission of the number of leaks occurring on small diameter cast iron mains (National Grid Brief at IV.27-28). National Grid argues that, based on its judgment, experience and knowledge of gas distribution operations, the appropriate measure is the aggregate leak rate, which measures the number of leaks over the total population of mains to derive a metric that is comparable across companies of all sizes and system composition (National Grid Brief at IV.28).

e. Term of TIRF Mechanism

National Grid disputes the Attorney General's assertion that it failed to provide any basis for its claim that the ability to enter into longer-term construction contracts will allow for more cost-effective procurement of such resources (National Grid Reply Brief at 41). On the contrary, National Grid claims that the record shows that: (1) National Grid will use a mix of internal and external resources and has not made any decision to rely exclusively on external labor to complete TIRF related projects; (2) the contract terms would be in the range of five years; and (3) a contract term in the range of five years is acknowledged to allow for more cost-effective procurement (National Grid Reply Brief at 42).

f. Worst-First Basis Sequence of Pipe Replacement

Regarding the Attorney General's recommendation to use the worst-first basis for pipe replacement, National Grid claims that the Department has previously considered the issue of sequencing of pipe replacement activities and has declined to mandate a specific method for replacing mains infrastructure including the use of the worst-first approach (National Grid Reply Brief at 44-45, citing D.P.U. 09-30, at 142-143; D.T.E. 05-27, at 37-38). Instead, National Grid claims that it has submitted evidence describing an eight-step prioritization approach for repair of leak-prone facilities (National Grid Reply Brief at 43-44, 46 citing Exhs. NG-JBH-1, at 49-53; DPU-6-30).

g. Separate TIRF Mechanism By Company

National Grid opposes the Attorney General's recommendation to establish separate TIRF mechanisms applicable to each of the National Grid Massachusetts gas companies (National Grid Reply Brief at 49). National Grid states that the Department approved the legal consolidation of Boston Gas and Essex Gas on September 3, 2010, in D.P.U. 09-139 (National Grid Reply Brief at 49). National Grid explains that the Lowell and Cape divisions of Colonial will no longer exist under its rate consolidation proposal (National Grid Reply Brief at 49). National Grid adds that Essex Gas customers will benefit from this consolidation because the O&M offset is bigger on a consolidated basis than Essex Gas would have had on its own and that the average cost per mile per customer is less when spread across a bigger customer base (National Grid Reply Brief at 49-50, citing RR-DPU-27; RR-AG-24). National Grid claims that the same holds true for the Colonial Gas system (National Grid Reply Brief at 49-50, citing RR-DPU-27; RR-AG-24).

h. O&M Offset

Regarding the Attorney General's suggestion to use the 2009 leak-prone leak rate to establish the O&M offset for use in the TIRF mechanism, National Grid states that it does not disagree with the premise that the actual number of leaks that are repaired on the system each year will vary as a result of many factors, including weather (National Grid Brief at IV.28).

For example, National Grid notes that the leak-prone leak rate in 2009 was 1.77 instead of the 1.42 rate experienced in 2008 (National Grid Brief at IV.28, citing Exh. AG-7-9; Tr. 5, at 564). Rather than picking a single year as the basis for calculation, National Grid proposes to apply a three-year rolling average, using 2007, 2008 and 2009 to establish the O&M offset for TIRF-related projects completed in 2010 (National Grid Brief at IV.28). National Grid states that it would update this average in sequential annual TIRF filings (National Grid Brief at IV.28).

i. TIRF Impact on Cost of Capital

National Grid rebuts the Attorney General's suggestion to reduce National Grid's ROE or deny the TIRF mechanism because the Companies have significantly decreased main replacements in the years 2002 through 2007 (National Grid Brief at IV.24, citing Attorney General Brief at 71-72). National Grid claims that the Attorney General has ignored evidence showing that the year-to-year reduction in leak-prone inventory results from the completion of replacement projects through all capital programs conducted by National Grid and not just the subset of integrity related projects that would be included in the TIRF (National Grid Brief at IV.25, citing RR-AG-19). For example, National Grid notes that the Department's Order in D.T.E. 03-40, at 32 references that, as a result of new engineering software, Boston Gas was able to identify and reinforce approximately 1,500 areas on its system in the years 2001 through 2002 where low pressures could be expected during design conditions (National Grid Brief at IV.25). National Grid claims that pipeline replacements made in those years to improve system reliability would have contributed to the reduction of leak-prone inventory but would not have continued into later years (National Grid Brief at IV.25).

Regarding the Attorney General's recommendation to reduce National Grid's cost of capital in the TIRF mechanism, National Grid contends that a decision by the Department to apply a lower rate of return for the projects completed as part of the targeted infrastructure replacement program would be viewed negatively by the market and by National Grid management who must satisfy the expectation of investors, such that the Companies would not move forward with the proposed TIRF program (National Grid Brief at IV.28-29). Under such circumstances, National Grid states that it would make all investments that are necessary to maintain the safety and reliability of the system on a year-to-year basis as it has in the past, and seek recovery of TIRF costs through sequential base rate proceedings (National Grid Brief at IV.29). National Grid argues that even if the Department were to apply the same rate of return for the TIRF mechanism as for rate base in the revenue requirement but were to adopt the Attorney General's recommended return on equity of 9.0 percent, National Grid would not be in a position to obtain the capital necessary to conduct accelerated replacement activities through the TIRF (National Grid Brief at IV.29).

j. Incremental Cost Language in TIRF Tariff

National Grid argues that the Department need not address the Attorney General's request to include a definition of incremental costs in the tariff implementing the TIRF (National Grid Brief at IV.30). National Grid explains that all work that will be performed through the TIRF will be capital work, which is incremental to the amount included in rates because the Department's ratemaking standards allows capital additions in rate base only through the end of the test year used in setting rates (National Grid Brief at IV.29). Further, National Grid argues that it has proposed a comprehensive mechanism designed to ensure that there is no double recovery of overheads and burdens through base rates and through the TIRF recovery mechanism (National Grid Brief at IV.29-30, citing RR-DPU-107, RR-DPU-119).

k. Other Arguments

National Grid agrees with TEN's suggestion that the costs to be recovered through the TIRF be allocated among rate classes using a rate base allocator instead of a proposed per therm volumetric rate applicable to all customer classes (National Grid Brief at IV.30). National Grid explains that, because the costs that will be recovered through the TIRF are rate base type of costs that will be placed into rate base at a later date, it is reasonable to recover these costs from customers using a rate base allocator (National Grid Brief at IV.30, citing RR-TEN-4).

National Grid does not agree with DOER's and TEN's recommendations to reduce its proposed TIRF cap from three percent to two percent or two and one-half percent, respectively. National Gird argues that the one percent cap approved in D.P.U. 09-30 was based on Bay State's determination that the cap was sufficient, based on historical experience, to allow for recovery of the company's necessary TIRF costs (National Grid Brief at IV.30-31, citing D.P.U. 09-30, at 116, 120-121, 130-131). National Grid concludes that Bay State's one percent cap for its TIRF mechanism was sized to achieve the goals of its particular accelerated infrastructure replacement program (National Grid Brief at IV.31, citing D.P.U. 09-30, at 114-116). Likewise, National Grid argues that, in this case, it determined a three percent cap was necessary to achieve the goals of its proposed targeted infrastructure replacement program (National Grid Brief at IV.31, citing RR-TEN-6; RR-DPU-20). National Grid argues that any reduction in the three percent cap would threaten the public safety and public interest benefits that should result from the TIRF (National Grid Brief at IV.31-32).

Finally, National Grid argues that NEGWA's claim that the cost of outside contractors engaged by National Grid can be 6.7 times the cost of National Grid's own employee workforce is inaccurate (National Grid Brief at IV.33). National Grid contends that NEGWA's cost comparison fails to appreciate that differences in cost can be influenced by numerous factors (National Grid Brief at IV.33). National Grid states that, even within the same geographic areas of Massachusetts, care must be taken to compare like jobs because job complexity in mains installations varies greatly by pipe material, pipe diameter, road and traffic conditions and subsurface soil conditions (National Grid Brief at IV.34).

D. Analysis and Findings

1. Introduction

The Department has recognized that there are public safety, service reliability, and environmental issues associated with the continued existence and aging of bare steel infrastructure in gas companies' distribution systems. D.P.U. 09-30, at 133. Faced with an aging infrastructure that is experiencing corrosion and leaks, National Grid is currently engaged in a program to replace unprotected bare steel and cast iron and wrought iron mains with more modern materials (Exhs. NG-NS-1, at 7-8; NG-JBH-1, 8-14)).

In D.P.U. 09-30, the Department approved a ratemaking mechanism for Bay State designed to support an expedited replacement of steel infrastructure. There, the Department found that the approval of a TIRF would likely provide an incentive for a more aggressive replacement of aging infrastructure. D.P.U. 09-30, at 133. Without approval of a TIRF, recovery of the capital investments would be delayed until a future rate case. The Department found that providing more certainty for, and more timely recovery of, the revenue requirement associated with capital expenditures for bare steel replacement between rate cases will provide appropriate incentives for a company to expedite the replacement of the unprotected steel in its distribution system. D.P.U. 09-30, at 133-134. Further, the Department found that such accelerated replacement was desirable given the potential benefits to public safety, service reliability, and the environment. D.P.U. 09-30, at 133.

Here, National Grid requests approval of a TIRF to support its targeted infrastructure replacement program. The merits of National Grid's TIRF proposal must be evaluated in the context of its current circumstances, especially in light of the framework of its decoupling mechanism.

The Attorney General argues that the TIRF would undermine the efficacy of Boston Gas' current PBR plan (Attorney General Brief at 79, citing Tr. 4, at 474; Attorney General Reply Brief at 19, citing Exh. AG-DED-1, at 89). However, as discussed in Section III, above, the Department has determined that Boston Gas' PBR plan shall be terminated upon implementation of new rates in this proceeding. Therefore, the relationship between the TIRF proposal and the PBR plan is no longer an issue.

The Attorney General and NEGWA also challenge the necessity of the TIRF. In particular, the Attorney General argues that there is no evidence to demonstrate that National Grid's ability to provide safe, economic, and reliable service will be compromised without the adoption of the proposed TIRF (Attorney General Brief at 79, citing AG-DED-1, at 89; Attorney General Reply Brief at 13, 19, citing Exh. AG-DED-1, at 89). By contrast, arguing that it is desirable to replace unprotected bare steel and small diameter cast iron pipes with more modern material, DOER generally supports National Grid's implementation of the TIRF. TEN also accepts the need for a TIRF but, as discussed below, urges the Department to make certain changes to National Grid's proposed mechanism.

National Grid accepts that it must provide safe and reliable service to its customers regardless of the existence or ultimate design of the TIRF (Exhs. NG-JBH-1, at 8; NG-MDL-1, at 88). However, it contends that, all else equal, it will increase capital investment in TIRF-related projects if the Department approves the TIRF (Exh. NG-JBH-1, at 13-16). As noted above, the Department has recognized the public safety, service reliability, and environmental issues associated with the continued existence and aging of bare steel infrastructure. D.P.U. 09-30, at 133. Although the evidence before us does not conclusively determine the extent to which the TIRF will accelerate the replacement of bare steel and small diameter cast iron and wrought iron mains, we conclude that approval of the TIRF is likely to provide an incentive for more sustained replacement of such aging infrastructure. Further, we conclude that a more sustained replacement of bare steel, small diameter cast iron, and wrought iron mains is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. D.P.U. 09-30, at 133.

Based on these considerations, we find that implementation of a TIRF permits and facilitates National Grid's long term strategy of bare steel and small diameter cast iron and wrought iron mains replacement while lessening the impediment of current capital constraints. Further, with the modifications discussed below, we find that the TIRF provides sufficient protection for ratepayers. Accordingly, the Department approves a TIRF for National Grid with the modifications discussed below.

We note that the TIRF mechanism approved herein is designed to be a special ratemaking mechanism, limited in both scale and scope, to support the replacement of bare steel, cast iron and wrought iron mains and other associated facilities that National Grid deems need special attention as it performs its public service obligation in maintaining a safe and reliable distribution system. Such a mechanism is not designed to supplant traditional ratemaking. As National Grid correctly acknowledged, it can and must continue to invest all capital necessary to maintain its distribution system, at a level beyond what it could recover through the TIRF if the performance of its service obligations demands it (see Exh. NG-MDL-1, at 88).

2. Targeted Infrastructure Replacement Program

National Grid states that during its initial ten-year term, its proposed targeted infrastructure replacement program is designed to achieve an average aggregate leak rate of 0.32 leak per mile, or a 50 percent reduction from its average aggregate leak rate of 0.64 leak per mile as of 2008 (Exhs. NG-JBH-1, at 11, 28; AG-7-4, Att.).[80] The Attorney General argues that the pace of National Grid's proposed targeted infrastructure replacement program is too aggressive (Attorney General Brief at 76). The Attorney General argues that National Grid's goal should instead be 0.536 leaks per mile of leak-prone pipes, which she contends could be achieved over the next five years (Attorney General Brief at 76). Conversely, TEN takes no issue with National Grid's target leak rate but opines that the speed of replacement offered by National Grid is unnecessarily swift and, therefore, recommends that the Department extend the term of the proposed infrastructure replacement program from ten to 15 years (TEN Brief at 9, 12).

A review of the record shows that the 22 local gas distribution companies in the peer group used as a benchmark by National Grid have a wide range of distribution infrastructure systems (Exh. AG-7-4, Att.). For example, ten of those companies have less than 100 miles of unprotected steel mains in their inventory compared to the 1,192 miles for National Grid (Exh. AG-7-4, Att.). Regarding cast iron and wrought iron mains, two of those companies have no inventory, one company has one mile, another company has three miles, and one company has eleven miles compared to the 2,478 miles of cast iron and wrought iron mains of National Grid (Exh. AG-7-4, Att.).

80 As noted above, National Grid claims that this average aggregate leak rate is comparable to the average aggregate leak rate for a peer group of 22 regional local gas distribution companies and comparable to the 2008 average aggregate leak rate of 0.29 leaks per mile of National Grid's U.S. gas distribution system exclusive of its Massachusetts gas operations (Exh. NG-JBH-1, at 28).

In addition, no definitive correlation has been shown to exist between leak rates and inventory of leak-prone mains, such that a company with a high leak rates does not necessarily have a high proportion of leak-prone mains in its systems (Exhs. AG-DED-1, at 80; Sch. DED-18; AG-7-4, Att.; RR-DPU-101; RR-DPU-102, Att.). Therefore, we are not persuaded that an average aggregate leak rate of 0.32 leaks per mile is an appropriate target to be used for determining the pace of replacement of National Grid's leak-prone facilities.

In addition, our review of the record shows that the annual level of leaks does not necessarily dictate National Grid's historical pace of replacement. In the case of Boston Gas' distribution system, for example, the numbers of leaks from unprotected steel mains in 2005 through 2009 were: 1,370 leaks in 2005; 1,441 leaks in 2006; 1,078 leaks in 2007; 1024 leaks in 2008; and 1,332 leaks in 2009, representing a 38 leaks reduction from 2005 to 2009 or a 0.3 percent decrease (Exh. DPU-6-23, Att.). However, for the same period from 2005 through 2009, National Grid replaced for Boston Gas 14.88 miles, 8.84 miles, 15.16 miles, 19.96 miles, and 34.25 miles of bare steel, respectively (Exh. DPU-6-23, Att.; RR-DPU-17).[81] The number of miles replaced in 2005 compared to that in 2009, for example, represents an

[81] For Boston Gas, its inventory of non-cathodically protected steel mains decreased by 504 miles, from 1,922 miles in 1990 to 1,418 miles in 2009, for a 19-year average reduction of 26.5 miles per year (Exh. DPU-6-23, Att.). For Essex Gas, the corresponding inventory decreased by 74 miles, from 100 miles in 1990 to 26 miles in 2009, for a 19-year average reduction of 3.9 miles per year (Exh. DPU-6-23, Att.). For Colonial Gas the inventory decreased by 585 miles, from 904 miles in 1990 to 319 miles in 2009, for a 19-year average reduction of 30.8 miles per year, a more accelerated rate of reduction than Boston Gas' (Exh. DPU-6-23, Att.).

increase of 19.37 miles or 130 percent increase as opposed to the 0.3 percent decrease in the number of leaks for the same period.[82]

The same observation can be made for small diameter cast iron and wrought iron mains during the 2005 through 2009 period for the Boston Gas system.[83] More specifically, the record shows that the number of leaks from small diameter cast iron and wrought iron mains in the Boston Gas distribution system in 2005 through 2009 were: 4,090 leaks in 2005; 3,148 leaks in 2006; 3,027 leaks in 2007; 3,398 in 2008; and 3,864 leaks in 2009 (Exh. DPU-6-23, Att.). The 3,864 leaks experienced in 2009 represent a 6.0 percent decrease from the 4,090 leaks experienced in 2005 (Exh. DPU-6-23, Att.). However, for the same period National Grid replaced for Boston Gas 14.87, 22.98, 12.45, 7.92, and 24.87 miles of small diameter cast iron and wrought iron mains (RR-DPU-17, at 2). The 24.87 miles of small diameter cast iron and wrought iron mains replaced in 2009, for example, represents a 10.0 mile increase

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82 The annual numbers of leaks from unprotected steel mains in 2000 through 2004 for Boston Gas were 969, 1,104, 1,080, 1,249, and 1,128, respectively, compared to the corresponding number of miles of bare steel mains replaced of 12.17, 12.42, 13.45, 12.49, and 13.87 miles, respectively (Exh. DPU-6-23, Att.; RR-DPU-17, at 1). Here, no dramatic difference is noted between the annual changes in leaks and the corresponding changes in miles of mains replaced.

83 The number of corrosion leaks arising from small diameter cast iron and wrought iron mains for Boston Gas increased by 1,784 leaks, from 2,080 in 1990 to 3,864 in 2009, for a 19-year average increase of 94 leaks per year (Exh. DPU-6-23, Att.). The number of leaks for Essex Gas increased by eleven leaks, from 106 in 1990 to 117 in 2009, for a 19-year average increase of 0.6 leaks per year (Exh. DPU-6-23, Att.). Finally, the number of leaks for Colonial Gas decreased by 34 leaks, from 107 in 1990 to 73 in 2009, for a 19-year average decrease of 1.8 leaks per year (Exh. DPU-6-23, Att.).

over the 14.87 miles replaced in 2005 or a 67 percent increase, as opposed to the 6.0 percent decrease in leaks over the same period (Exh. DPU-6-23, Att.; RR-DPU-17, at 2).[84]

Based on this review, we conclude that the number of historical leaks from non-cathodically protected steel, cast iron, and wrought iron mains in National Grid's distribution system does not necessarily dictate the pace of replacement of those mains.[85] In addition, our review below of National Grid's ten-year targeted infrastructure program shows that the pace of replacement does not necessarily comport with the above-reviewed leak occurrences and pace of leak-prone mains replacements.

In the case of Boston Gas, for example, for which National Grid plans to replace 40.2 miles[86] of bare steel per year starting in 2011, this pace of replacement represents a 26.8 mile or 199 percent increase over the 13.45 miles replaced during the 2002 test year for

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84 The annual numbers of leaks from small diameter cast iron and wrought iron mains for Boston Gas in 2000 through 2004 were 3,272, 3,316, 2,496, 4,258, and 3,866, respectively, compared to the corresponding number of miles replaced of 26.68, 23.65, 35.61, 23.79, and 17.00, respectively (Exh. DPU-6-23, Att.; RR-DPU-17, at 2). Similarly, no dramatic difference is noted between the annual changes in leaks and the corresponding annual changes in miles replaced for cast iron and wrought iron mains (Exh. DPU-6-23, Att.; RR-DPU-17, at 2).

85 For example, in the case of cast iron replacements, National Grid explained that several factors drive replacement decisions related to public works, including: (1) encroachment by other underground construction on the street such as sewer separation projects; (2) scheduled city, town, or state roadway construction and repaving; and (3) other major municipal or state projects such as bridge reconstruction or public building construction in the vicinity of cast iron facilities (RR-DPU-16; RR-DPU-16 (Supp); Tr. 4, at 459-461).

86 National Grid's planned annual replacement of 40.2 miles of non-cathodically protected steel mains for Boston Gas represents 80 percent of the 50.0 miles of total annual planned replacement of non-cathodically steel mains from 2011 through 2020 for National Grid's Massachusetts gas operations (RR-DPU-24, Att. at 1, 5).

its last rate case and a 6.0 mile or 17 percent increase over the historical peak level of 34.25 miles replaced during the 2009 test year (RR-DPU-17, at 1; RR-DPU-24, Att. at 1). In the case of Essex Gas, National Grid replaced 1.4 miles of bare steel in 2009 and intends to replace a total of 2.0 miles in 2010 (RR-DPU-17, at 1; RR-DPU-24, Att. at 2). However, starting in 2011 through the end of the ten-year targeted infrastructure replacement program, National Grid plans for Essex Gas to replace annually 0.7 mile of bare steel, which represents a reduction of 50 percent and reduction of 65 percent from the 2009 and 2010 levels, respectively (RR-DPU-24, Att. at 2).

Similarly, in the case of Colonial Gas (Lowell), National Grid replaced 1.97 miles of bare steel in 2009 and intends to replace 8.0 miles in 2010 (RR-DPU-17, at 1; RR-DPU-24, Att. at 3). Starting in 2011 through the end of the ten-year targeted infrastructure replacement program, National Grid plans for Colonial Gas (Lowell) to replace 2.2 miles per year (RR-DPU-24, Att. at 3). This annual replacement pace represents an increase of 12.0 percent over the 2009 level and a 73 percent decrease from the 2010 level (RR-DPU-24, Att. at 3). However, in the case of Colonial Gas (Cape Cod), National Grid replaced 3.9 miles of bare steel in 2009 and intends to replace 4.0 miles in 2010 (RR-DPU-17, at 1; RR-DPU-24, Att. at 4). Starting in 2011 through the end of the ten-year targeted infrastructure replacement program, National Grid plans for Colonial Gas (Cape Cod) to replace 6.8 miles per year

(RR-DPU-24, Att. at 4). This pace of annual replacement represents a 75 percent increase over the 2009 level and a 70 percent increase over the 2010 level (RR-DPU-24, Att. at 4).[87]

Although we noted above that National Grid's pace of replacement in its targeted infrastructure replacement program does not necessarily comport with leak occurrences, we will not determine here or endorse a specific term, scope, pace, or approach for National Grid in maintaining and operating its distribution systems. The Companies are obligated to provide safe and reliable gas distribution service.[88] The Department will not substitute its judgment for utility management's job as to how best to meet and fulfill its service obligations to maintain

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87 We note that the same pace of replacement applies to the planned replacement of small diameter cast iron and wrought iron mains. In 2009 National Grid replaced a total of 24.9 miles and in 2010 it intends to replace 33 miles in the Boston Gas distribution system (RR-DPU-17, at 2; RR-DPU-24, Att. at 1). From 2011 through 2014, National Grid plans for Boston Gas to replace 95.6 miles, 113.8 miles, 136.5 miles, and 154.7 miles, respectively (RR-DPU-24, Att. at 1). Starting in 2015, the planned level of replacement for Boston Gas will remain at 172.9 miles per year (RR-DPU-24, Att. at 1).

88 See Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009) (The Department's comprehensive oversight powers are to ensure reliable and safe services by gas and electric distribution companies to the public); Rate Decoupling, D.P.U. 07-50, at 5 (2007) (a goal of the Department is to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); Incentive Regulation, D.P.U. 94-158, at 3 (1995) (since it was established in 1919, the goal of the Department has been to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); Electric Industry Restructuring, D.P.U. 95-30, at 6 (1995) (same); Integrated Resource Planning, D.P.U. 94-162, at 51-52 (1995) (the Department emphasizes that electric companies are still required to provide safe, reliable, least-cost electric service to their ratepayers, even though companies will no longer be required to submit initial resource portfolios); Mergers and Acquisitions, D.P.U. 93-167-A at 4 (1994) (Department to ensure that utilities subject to its jurisdiction provide safe and reliable service at the lowest possible cost to society).

and operate its system consistent with safety, reliability and other considerations. D.T.E. 05-27, at 36-37, 39. Therefore, the TIRF mechanism as modified and approved here will be effective until National Grid's next general rate case.[89]

In consideration of National Grid's exercise of management discretion in this regard, we will not address the operational issues raised by NEGWA or its proposal to develop an alternative pipe replacement program, which would include a program for cathodic protection of all unprotected steel.[90] Similarly, we will not address the Attorney General's recommendation to develop a more appropriate leak performance measure nor require use of the worst-first basis of sequencing pipe replacement. Nonetheless, we emphasize that the TIRF does not allow the Companies to invest capital dollars irresponsibly. Projects undertaken within the scope of National Grid's targeted infrastructure replacement program will be subject to a prudence review in each annual TIRF filing. During these annual filings, interested parties will have the opportunity to examine the reasonableness of each individual project undertaken.

Finally, with respect to the issue of whether it is reasonable to include in the TIRF annual revenue requirement expenditures on cast iron and wrought iron mains replacement in

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89 The Attorney General recommends that should the Department approve the TIRF tariff, it should open a brief proceeding to set the appropriate limits and thresholds for the TIRF program (Attorney General Reply Brief at 23). Based on our findings here and modifications to the proposed TIRF, we find that it is not necessary to open such a proceeding.

90 The Department has addressed the service quality issues raised by NEGWA in Section XII, below.

addition to bare steel mains, given the leak rates for cast iron and wrought iron mains, we find that National Grid has adequately demonstrated that including them in the TIRF is in the public interest (Exhs. NG-JBH-1, at 11; DPU-6-23, Att.). Accordingly, National Grid may include such investments in its TIRF as specified in record request DPU-118, Att. A at 4-5, 10-11.[91]

3. TIRF Mechanism

a. Introduction

The parties in this proceeding raised a number of issues regarding the design of National Grid's proposed TIRF including: (1) the three percent cap on the annual TIRF revenue requirement; (2) the carrying charge on the annual TIRF revenue requirement resulting from the billing delay; (3) the establishment of two TIRFs (i.e., a TIRF for Boston Gas-Essex Gas and a TIRF for Colonial Gas); (4) the calculation of TIRF savings and O&M offsets; (5) the ratemaking treatment of labor overhead and clearing account burden and recovery of incremental costs; (6) the method of rate recovery for the TIRF revenue

[91] In order to ensure that the Companies' targeted infrastructure replacement program activities are eligible for inclusion in the TIRF, the Companies must provide as part of their annual TIRF filings, complete and contemporaneous documentation demonstrating the eligibility of each individual project. Such documentation must include, but will not be limited to, capital authorizations and closing reports that clearly indicate that the projects included are TIRF-related, and narrative explanations of any positive variances from estimated to actual costs. In addition, the Companies must include a progress report detailing the miles of replacements and remaining inventory, cost per mile of replacement with at least three-year historical cost comparison, aggregate leak rates per total mile and leak rate per mile for each type of leak-prone main and a summary of the year's progress, including detailed explanations for accelerated or decelerated rates of replacement and a schedule similar to, but not limited by, the continuing historical information provided in the attachment to Exhibit DPU-6-23.

requirement; and (7) a separate ROE for TIRF investments. We discuss each of these issues below.

b. Cap on Annual TIRF Revenue Requirement

As described above, National Grid proposes to include a three percent cap for the TIRF revenue requirement, plus a one percent cap for its proposed revenue decoupling mechanism, discussed in Section IV, above, for a total cap of four percent for these two mechanisms (Tr. 5, at 636-637). Intervenors, including TEN and the Attorney General, raise concerns that a three percent cap for the TIRF revenue requirement is not appropriate.

Although the Department approved a total cap of four percent for Bay State, we approved a three percent cap for decoupling and a one percent cap for the TIRF. D.P.U. 09-30, at 116, 130, 134. In approving the one percent cap for Bay State's TIRF, the Department found that the TIRF would effectively expedite infrastructure replacement and would limit the annual increase and mitigates rate continuity concerns. D.P.U. 09-30, at 134.

Assuming that the proposed TIRF had been in place in 2009, the incremental annual TIRF revenue requirement recoverable in 2010 for actual TIRF-related investments made in 2009, would have been $10,356,368 for Boston Gas-Essex Gas (Exhs. DPU-6-9 (BOS) (Att. B), at 1; Tr. 5, at 641-642; RR-DPU-19). Therefore, the annual incremental TIRF revenue requirement associated with Boston Gas-Essex Gas' level of bare steel and cast iron replacement for 2009 represents only 0.68 percent of the actual total firm billed revenues for Boston Gas-Essex Gas in 2009 of $1,523,584,919 (RR-DPU-19; RR-DPU-7, Att. (BOS) at 1). As noted above, Boston Gas replaced a historical peak of 34.25 miles of bare steel for 2009

(Exh. AG-7-10, Att. at 14; RR-DPU-17, at 1).[92] Therefore, the amount of TIRF-related investments for 2009 was at a historical high level and yet the resulting incremental TIRF revenue requirement would have been less than a one percent cap.[93]

Similarly, in the case of Colonial Gas, the incremental annual TIRF revenue requirement recoverable in 2010, assuming that the proposed TIRF mechanism had been in place in the preceding year, is equal to $834,931 (RR-DPU-19; RR-DPU-7, Att. (COL) at 1). This TIRF revenue requirement represents 0.26 percent of the total firm billed revenue for Colonial Gas 2009 in the amount of $320,652,678 (RR-DPU-19; RR-DPU-7, Att. (COL) at 1).[94]

Based on the foregoing analysis, we do not approve National Grid's proposed three percent cap for the TIRF. The purpose and intent of a special ratemaking mechanism like the TIRF is to provide utility companies a reasonable level of financial incentives to address a specific component of their distribution infrastructure that is deemed to be in need of

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92 In addition, National Grid replaced 24.87 miles of cast iron in 2009, which is the third highest cast iron mains replacement over the period from 2000 to 2009, with 35.61 miles and 26.68 miles replaced in 2002 and 2000, respectively (RR-DPU-17, at 2).

93 Based on the 2009 actual total firm billed revenues for Boston Gas-Essex Gas, National Grid's proposed three percent cap would have been equal to $45,707,548 and could have provided Boston Gas-Essex Gas an additional potential amount of $35.4 million in annual incremental TIRF revenue requirement for recovery in 2010 (RR-DPU-7, Att. (BOS) at 1).

94 Based on the 2009 actual total firm billed revenues for Colonial Gas, National Grid's proposed three percent cap would have been equal to $9,619,580 and could have provided Colonial Gas an additional potential amount of $8.8 million in annual incremental TIRF revenue requirement for recovery in 2010 (RR-DPU-7, Att. (COL) at 1).

special attention. Such a special ratemaking treatment is not intended to provide an all-out financial support for a specifically established term and program of mains replacement nor supplant or eliminate the disciplining role of regulatory lag inherent in traditional ratemaking principles. Further, we stress that the TIRF does not allow the Companies to invest capital dollars irresponsibly. D.P.U. 09-30, at 134.

Here, we find that a one percent cap that limits the annual change in revenue requirement associated with the TIRF to one percent of total revenues for the prior calendar year gives sufficient protections for ratepayers as it both limits the annual rate increase and mitigates rate continuity concerns. D.P.U. 09-30, at 134. Further, we find that a one percent cap will provide an appropriate incentive for National Grid to expedite the replacement of its leak-prone mains and associated services in its distribution systems. D.P.U. 09-30, at 134.

Any TIRF revenue requirement in excess of that one percent cap will not be deferred or recovered in any subsequent annual TIRF revenue requirement filings and, instead, National Grid will be able to recover those expenditures under traditional ratemaking process. As described above, National Grid replaced a relatively high level of bare steel and cast iron mains during the 2009 test year. The TIRF mechanism would have enabled National Grid to immediately include these items in rate base thereby allowing it a return on and return of such investments, without having to file a rate case, as the annual incremental revenue requirements from such investments did not exceed the above-determined one percent cap. There is no evidence on the record that demonstrates that National Grid was unable to meet its service obligations in 2009 including the provision of safe distribution services. Further, going forward, imposition of a one percent cap does not prevent National Grid from performing its service obligations through the maintenance of its distribution systems, including the replacement of additional non-cathodically protected steel, cast iron, and wrought iron mains and associated services. To the extent that additional investments in these areas are required that could not be supported under the TIRF as a result of a one percent cap, National Grid will be able to recover those expenditures under traditional ratemaking process. As National Grid itself recognized, the cap on the annual TIRF revenue requirement, while it caps the rate impact to customers, does not impose any limit on the level of investment that can be undertaken in a given year, thereby preserving the full discretion of National Grid to manage the safety and reliability of its distribution system (Exh. NG-MDL-1, at 88).

c. Carrying Charge

In approving Bay State Gas' TIRF in D.P.U. 09-30, at 130, the Department identified three distinct differences in that mechanism compared to the two previous proposals rejected by the Department in D.T.E. 05-27 and D.P.U. 07-89. One of those three differences noted by the Department that weighed in favor of our approval was that that Bay State did not seek to recover carrying charges in the TIRF. D.P.U. 09-30, at 130.

Here, National Grid argues that a billing delay carrying charge is needed because the acceleration of replacement activities for leak-prone facilities will require substantially more capital on a year-to-year basis than National Grid has required in the past (Exh. NG-MDL-1, at 86). However, the Department has previously expressed concerns about utility companies' acceleration of capital expenditures supported by a special ratemaking mechanism that would allow immediate cost recovery because it reduces and potentially eliminates 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.[95]

Our decision above to reduce National Grid's proposed cap on the annual incremental TIRF revenue requirement to one percent addresses the above-expressed concerns, Similarly, the absence of a carrying charge on the billing delay of the annual TIRF revenue requirement is a form of regulatory lag that disciplines companies in maintaining an appropriate balance between investing in capital improvements and incurring O&M expenses. Accordingly, and consistent with the Department findings in D.P.U. 09-30, the Department denies National Grid's proposed billing delay carrying charge.

d. Company-Specific TIRF

The Attorney General recommends that the Department establish a TIRF that would be applicable separately to Boston Gas, Essex Gas, Colonial Gas (Cape Cod), and Colonial Gas (Lowell) in order to avoid cross-subsidization (Attorney General Brief at 83; Attorney General Reply Brief at 22). National Grid opposes the Attorney General's proposal claiming that a combined TIRF for Boston Gas and Essex Gas and a combined TIRF for Colonial Gas' Cape Cod and Lowell divisions would be beneficial to customers (National Grid Reply Brief at 49).

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95 The Department has recognized that in satisfying their obligation to provide safe and reliable service to their ratepayers, utility companies have the incentive to invest in capital improvements rather than O&M expenses, even if a capital improvement represents a sub-optimal solution as compared to non-capital production factors. D.P.U. 09-39, at 80.

The Department has recently approved the merger of Boston Gas and Essex Gas in D.P.U. 09-139. In that proceeding, the Department acknowledged the Attorney General's concerns regarding the potential consolidation of National Grid's rates, adding that such concerns are better left for investigation and evaluation in the instant docket. D.P.U. 09-139, at 19.

In Section XII.D.3, below, we find that consolidating the rates for Boston Gas and Essex Gas is consistent with Department precedent and would result in just and reasonable rates. In light of these findings, we find that a consolidated TIRF applicable to Boston Gas-Essex Gas is appropriate. Although the leak repair unit costs for Boston Gas are more than twice that of Essex Gas and, correspondingly, Boston Gas has a higher O&M offset per mile of mains repaired than Essex Gas,[96] the savings determined by the application of the O&M offset is a relatively small component of the overall annual TIRF revenue requirement.[97] We find that the added complexity developing company-specific TIRFs cannot justify such a relatively small difference in one component cost included in the annual TIRF revenue requirement.

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[96] The combined bare steel and cast iron O&M leak repair unit cost in 2009 for Boston Gas was $2,486 per mile (RR-DPU-27). Multiplying this amount by 1.87, which is Boston Gas' 2009 leaks per mile on leak-prone pipes, results in an O&M offset of $4,650 per mile (RR-DPU-27). In the case of Essex Gas, the combined bare steel and cast iron O&M leak repair unit cost in 2009 is $1,084 per mile (RR-DPU-27). Multiplying this amount by 1.91, which was Essex Gas' 2009 leaks per mile on leak-prone pipes, results in an O&M offset of $2,073 per mile (RR-DPU-27).

[97] For example, using National Grid's pro-forma filing based on 2010 TIRF capital expenditures, the targeted infrastructure replacement saving from the O&M offset for the combined operations of Boston Gas and Essex Gas is $235,008 compared to the TIRF pro-forma revenue requirement of $10,778,807 recoverable in 2011 (Exh. NG-MDL-5-Boston Gas at 2). The targeted infrastructure replacement saving due to the O&M offset represents only 2.2 percent of the TIRF revenue requirement.

Further, we find that separate TIRFs for Boston Gas and Essex Gas would violate the Department's goal of rate simplicity. D.P.U. 09-30, at 374; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 135. Accordingly, we approve National Grid's proposal to establish a TIRF that is applicable to the combined operations of Boston Gas and Essex Gas.

Similarly, in the case of Colonial Gas (Cape Cod) and Colonial Gas (Lowell), the Department also finds in Section XII.D.3, below, that consolidating their rates is consistent with Department precedent and would result in just and reasonable rates. Therefore, we find that it is appropriate to establish one TIRF applicable to each of the two operating divisions of Colonial Gas. Although the O&M offset for Colonial Gas (Cape Cod) is 15.0 percent higher than that of Colonial Gas (Lowell),[98] the TIRF savings calculated based on the O&M offset is a relatively small component of the overall TIRF revenue requirement (Exh. NG-MDL-5-Colonial at 2-6).[99] Accordingly, we approve National Grid's proposal to establish a TIRF that

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98 The combined bare steel and cast iron O&M leak repair unit cost in 2009 for Colonial Gas (Lowell) are $2,369 per mile (RR-DPU-27). Multiplying this amount by 1.00, which is Colonial Gas' (Lowell) 2009 leaks per mile on leak-prone pipes, results in an O&M offset of $2,371 per mile (RR-DPU-27). In the case of Colonial Gas (Cape Cod), its combined bare steel and cast iron O&M leak repair unit cost in 2009 are $1,213 per mile (RR-DPU-27). Multiplying this amount by 2.26, which is Colonial Gas' (Cape Cod) 2009 leaks per mile on leak-prone pipes, results in an O&M offset of $2,736 per mile, which is 15 percent higher than that of Colonial Gas (Lowell) (RR-DPU-27).

99 For example, using National Grid's pro-forma filing based on 2010 TIRF capital expenditures, the targeted infrastructure replacement saving from the O&M offset for the combined operations of Colonial Gas (Cape Cod) and Colonial Gas (Lowell) is $32,952 compared to the 2011 TIRF pro-forma revenue requirement of $1,603,855 (Exh. NG-MDL-5-Colonial Gas at 2). This targeted infrastructure savings due to the O&M offset represents only 2.1 percent of the TIRF revenue requirement.

is applicable to the combined operations of Colonial Gas (Cape Cod) and Colonial Gas (Lowell).

e. O&M Offsets

The O&M offset per mile represents the weighted average cost of leak repairs on non-cathodically protected steel and small diameter cast iron and wrought iron mains, which will be multiplied by the total miles replaced during the annual TIRF investment period to determine the savings credited to ratepayers in the annual TIRF revenue requirement (Exhs. NG-JBH-1, at 26; NG-MDL-1, at 87; NG-MDL-5-Boston Gas at 2-6; NG-MDL-5-Colonial at 2-6; DPU-6-8; AG-7-9, Att; RR-DPU-27; RR-DPU-29; RR-DPU-118, Att. A at 12). The Attorney General claims that National Grid incorrectly calculated the proposed O&M offset by multiplying the average cost to repair a leak for 2009 by the 2008 average leaks per mile of mains, thereby resulting in lower O&M offsets that are more favorable to National Grid (Attorney General Brief at 82, citing Exhs. DPU-6-8; AG-7-9).[100] We find that in record request DPU-27, National Grid performed the appropriate calculations by consistently using 2009 cost data and 2009 leak rate data. National Grid has updated its proposed revised LDAC tariff by incorporating these updated O&M offsets (RR-DPU-118; Tr. 20, at 2915-2916). More specifically, National Grid proposes to use an O&M offset of $4,557 per mile of

100 The Attorney General recommends that, if the Department allows the TIRF, National Grid be directed to recalculate the O&M offsets by service territory and material, as reflected in Attachment Exhibit AG-7-9, using an average leak per mile of 1.77, rather than 1.42 (Attorney General Brief at 83).

repaired mains for Boston Gas-Essex Gas and an O&M offset of $2,518 per mile of repaired mains for Colonial Gas (RR-DPU-118, Att. A at 12; RR-DPU-27).[101]

The record shows that these O&M offsets are based on 2009 average leak repair costs and 2009 leaks per mile of leak-prone pipes (Exh. AG-7-9; RR-DPU-27). However, we expect that O&M expenses will increase over time due to a number of factors including inflation. As new leaks arise, and as National Grid performs repairs on leak-prone mains or replaces them with cathodically protected steel mains or plastic mains, the inventory of leak-prone mains will also change. Therefore, the two components used in determining the O&M offset (i.e., the cost of repair per mile and leaks per mile) will change over time. Accordingly, we find that setting a fixed O&M offset until National Grid's next rate case may not capture the dynamics of cost changes and leak rates.

National Grid does not disagree with the premise that the actual number of leaks that are repaired on the system each year will vary as a result of many factors, including weather (National Grid Brief at IV.28).[102] As noted above, National Grid recommends that instead of using a single year as the basis for calculation, the Department should apply a three-year rolling average (i.e., 2007, 2008 and 2009) to establish the O&M offset for TIRF projects

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101 In its initial filing, National Grid proposed an O&M offset of $3,456 per mile of repaired mains for Boston Gas-Essex Gas (Exhs. NG-MDL-1, at 87; NG-MDL-5-Boston Gas at 2-6; AG-7-9, Att.). In the case of Colonial Gas, National Grid initially proposed an O&M offset of $2,130 per mile of repaired mains (Exhs. AG-7-9; DPU-6-8).

102 National Grid, for example, notes that the 2009 leak rate in its leak-prone mains for its Massachusetts gas operations was 1.77 instead of the 1.42 rate experienced in 2008 (National Grid Brief at IV.28, citing Exh. AG-7-9; Tr. 5, at 564).

completed in 2010 (National Grid Brief at IV.28). In support of this recommendation, National Grid states that it will assemble the O&M offsets that would result from costs and leak rates in 2007, 2008 and 2009, to establish the three-year average for the first TIRF filing for rates to be effective on November 1, 2011, and update this average in sequential annual TIRF filings (National Grid Brief at IV.28).

We note that a three-year rolling average could provide stability in the O&M offset, as influenced by the two component factors that determine that offset. A more stable O&M offset would be consistent with the Department's rate structure goals of rate continuity and earnings stability. D.P.U. 09-30, at 373-374; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 134-135. However, the record in this proceeding does not provide verifiable costs for year 2007. National Grid's proposed approach was raised for the first time on brief and, therefore, the parties to this proceeding were not provided an opportunity to review this approach.

National Grid's updated O&M offsets are based on 2009 test year cost data (RR-DPU-27). Based on our traditional ratemaking approach of using test year cost data to establish charges for the rate year, we find that the O&M offset of $4,557 per mile of repaired mains for Boston Gas-Essex Gas and the O&M offset of $2,518 per mile of repaired mains for Colonial Gas are reasonable and appropriate (RR-DPU-118, Att. A at 12). Accordingly, we approve these O&M offsets for the TIRF-related project completed in 2010.

In its TIRF compliance filing for charges to be effective on November 1, 2011, we direct National Grid to file verifiable data, including but not limited to O&M leak repair costs and leak rate data for non-cathodically protected steel, small diameter cast iron, and wrought iron mains for calendar years 2008, 2009, and 2010. In that filing, the Department will determine whether it would be appropriate to use a three-year rolling average O&M offset or use the 2010 costs and leak rates data for determining the O&M offset for TIRF projects completed in 2011.

f. Incremental Costs and Labor Overhead and Clearing Account Burden

At the Department's request, National Grid has proposed a three-step process to preclude the possibility of an unintended double recovery of labor overheads and clearing account burdens (Tr. 5, at 689-691; Tr. 18, at 2590-2596; Tr. 20, at 2931-2938, 2942-2943; RR-DPU-107, at 2; RR-DPU-119; National Grid Brief at IV.29-30). If its three-step process is approved, National Grid argues that it is not necessary to adopt the Attorney General's recommendation to include an "incremental cost" standard in the TIRF section of the LDAC tariff because all work that will be performed through the TIRF will be capital work, which is incremental (National Grid Brief at IV.29-30, citing RR-DPU-107; RR-DPU-119).

In recommending the approval of National Grid's proposal, DOER notes that, subject to the annual TIRF cap, National Grid would only seek to recover the depreciation expense, labor overhead and clearing account burdens that exceed the level included in base rates (DOER Brief at 12). In addition, DOER notes that National Grid would also demonstrate that the percentage of capitalized TIRF-related overheads and burdens allocated to TIRF-related capital projects is equal to the ratio of TIRF to non-TIRF direct costs (DOER Brief at 12).

National Grid has filed an illustrative example describing the details of its proposed three-step process to ensure the avoidance of double recovery of labor overheads and burden costs through the TIRF (RR-DPU-119). Under this process, the level of labor overheads and clearing account burdens recovered through the base rates and the PRAF mechanism will be used as a basis for comparison to actual amounts incurred by National Grid on a year-to-year basis between rate cases, with the exception of the amortization of deferred pension and PBOP costs, which change annually in National Grid's PRAF mechanism (RR-DPU-119, at 1, Att. at 1). National Grid proposes that in its compliance filing to the Department's Order in this case, it would provide a schedule indicating the level of overheads and clearing account burdens recovered in base rates and the PRAF mechanism (RR-DPU-119, at 1; Att. at 1).

Although the above described process appears to be a reasonable way to prevent double recovery of overhead and burden costs, such process was proposed during the last days of evidentiary hearings and the parties were not given a reasonable opportunity to review and evaluate this proposal. However, as a starting point and for further evaluation in its first annual TIRF filing, we accept National Grid's three-step process. Accordingly, National Grid shall include in its compliance filing to this Order a schedule showing the level of labor overheads and clearing account burdens recovered through base rates and the PRAF mechanism.

Regarding the Attorney General's recommended definition of "incremental" to be inserted in the TIRF section of the LDAC tariff, we note that Section 6.11 of that proposed tariff specifies that it applies to annual "incremental" targeted infrastructure replacement gross plant investments allowable for inclusion in the TIRF (RR-DPU-118, Att. A at 4). Accordingly, given this tariff language and National Grid's three-step process designed to eliminate the possibility of double recovery, we find that additional language defining incremental in the TIRF section of the LDAC tariff is not required.

g. Rate Base Allocator for TIRF Revenue Requirement

Regarding TEN's recommendation to recover the TIRF costs based on a rate base allocator, instead of a company-wide per therm unit charge as National Grid proposed, the record shows that National Grid has indicated that it does not oppose such an approach (TEN Brief at 9-10, citing RR-TEN-4 (b); Tr. 3, at 212-213; TEN Reply Brief at 8). National Grid provided calculations for two alternative allocation methods, one based on mains allocator, and another on rate base allocator (RR-TEN-4, Att. at 1, 2). National Grid states that in each annual TIRF filing, it would allocate the annual TIRF costs to each group of customers[103] by multiplying the total company TIRF costs by the approved allocator and then dividing the resulting costs by the associated annual throughput (RR-TEN-4).

Because the TIRF investments will not only cover mains but also associated services and other eligible facilities, we find that a rate base allocator is more stable and appropriate basis for allocating TIRF-related costs. The record also shows that there are cost differences between the C&I high load factor rate classes versus the C&I low load factor rate classes (RR-TEN-4, Att. at 2). Accordingly, we find it appropriate to develop separate allocators for

103 National Grid identified two possible groupings of customer classes: (1) residential and C&I; and (2) residential, C&I high load factor, and C&I low load factor (RR-TEN-4).

these two sub-groups of C&I rate classes, as well as a separate allocator for the residential rate classes. This allocation method will enable National Grid to more appropriately recover its costs of providing service and give a more accurate basis for consumers' decision on how best to fulfill their needs, consistent with the Department's rate structure goal of efficiency. D.P.U. 09-30, at 373-374; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 134-135.

h. Return on Equity for TIRF Investment

The Attorney General proposes to reduce the allowed ROE for National Grid's TIRF investment to the yield on long-term A-rated utility bonds in order to prevent unjust shareholder enrichment and to reduce the Companies' incentive to engage in uneconomic mains and service line replacements (Attorney General Brief at 84-85, citing Exh. AG-TN at 16). The Department has previously addressed a similar issue. In D.T.E. 02-24/25, at 225 and Fitchburg Gas and Electric Light Company, D.P.U. 1214-D at 4-5 (1985), the Department held that cash is fungible and that it is neither appropriate nor feasible to allocate the Company's capital structure between its electric and gas divisions. For these same reasons, the Department finds that it is neither appropriate nor feasible to assign a lower ROE to National Grid's plant investments to be recovered through the TIRF. Moreover, there is no basis to conclude that the appropriate ROE for plant recovered through the TIRF is equal to A-rated utility bonds.

In addition, as discussed in Section XI.D.4, below, the Department has taken the Companies' TIRF into consideration in our determination of an appropriate ROE for National

Grid, which would be applied to all of the Companies' investments, TIRF and non-TIRF related. The Attorney General provided no basis for segregating plant items by relative risk and the Department sees no reason to depart from its precedent here.

E. Conclusion

In conclusion, we find that National Grid's proposed TIRF, as modified herein, strikes an appropriate balance between providing National Grid with reasonable ratemaking support for accelerating the replacement of leak-prone mains and associated facilities in its distribution system, and the need to insulate and protect ratepayers from undue rate increases. In addition, we find that such a TIRF, as modified, is consistent with Department precedent and that its operation will result in just and reasonable rates. Accordingly, we approve the sections of National Grid's proposed LDAC tariff relating to the TIRF as shown in its response to record request DPU-118, Attachment A, subject to the modifications required herein. In its compliance filing, the Department directs National Grid to revise that tariff consistent with the directives in this Order.

VII. TECHNOLOGY AND INNOVATION PROPOSAL

A. National Grid's Proposal

National Grid proposes to implement two new technology and innovation ("T&I") programs intended to address what the Companies identify as business challenges that affect their customers, including: (1) the identification and implementation of operating efficiencies to reduce or contain operating costs; (2) the maintenance of safety and reliability on its gas distribution system; (3) assisting customers in finding ways to lower their energy bills;

(4) climate change issues; and (5) broader societal issues such as job development (Exh. NG-SB-1, at 4). Specifically, National Grid proposes to implement: (1) a gas operations program; and (2) an end-use/renewables program (Exhs. NG-SB-1, at 7; NG-SB-3, at 2-22). The gas operations program will focus on the protection of assets, protection of the environment, and operations improvement (Exhs. NG-SB-1, at 7; NG-SB-3, at 2-4). The end-use/renewables program will focus on advanced energy efficiency,[104] clean transportation, and renewable gas[105] (Exhs. NG-SB-1, at 7; NG-SB-3, at 5-22). National Grid states that the implementation of these two T&I programs will require an annual investment of $4.7 million from ratepayers (Exh. NG-SB-1, at 8). National Grid proposes to fund this annual budget through a T&I surcharge billed to customers through the LDAF (Exh. NG-SB-1, at 9).[106]

The individual projects for both the gas operations programs and the end use/renewables program have not been finalized, although National Grid states that it has done an initial assessment of each project's benefits, costs, and probability of success (Exhs.

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104 National Grid categorizes the following energy efficiency measures as "advanced energy efficiency": (1) Ultra-High Efficiency Fire-tube Boilers; (2) Ultra-High Efficiency Water-tube Boilers; (3) High Efficiency Commercial Rooftop Furnace; (4) Residential Combined Heat and Power ("CHP"); (5) Residential Fuel Cells; (6) Advanced Commercial CHP; (7) Thermal Activated Air Conditioning; and (8) Advanced Solar Hybrid Hot Water Systems (Exh. NG-SB-3, at 5). These measures are not currently included in the Companies' approved three-year energy efficiency plan (Exhs. DPU-8-7; DPU-8-11; DPU-8-19).

105 Renewable gas, also known as biomethane, is pipeline quality gas derived from biomass that is fully interchangeable with natural gas (see Exh. AG-10-27; Tr. 6, at 839).

106 National Grid states that the proposed surcharge equates to $0.0422 per dekatherm, which would increase the average residential heating bill by approximately $0.51 per month (Exh. NG-SB-1, at 11).

NG-SB-3; NG-SB-4; Tr. 6, at 869). If the T&I proposal is approved, National Grid states that an annual investment plan will be established for the gas operations and end-use/renewables programs (Exh. NG-SB-1, at 10). Specific projects to be undertaken pursuant to the annual investment plan first will require approval by National Grid's management (Exh. NG-SB-1, at 10). National Grid states it will then present the projects to the Department for approval with a complete cost/benefit analysis. Once approved, National Grid will file a progress report with the Department after the programs have been in operation for a year (Tr. 6, at 867-868; Tr. 7, at 1008-1009). Based on the results of the progress report, the Company would propose additional sets of projects for subsequent years (Tr. 6, at 867-868; Tr. 7, at 1008-1009).

B. Positions of the Parties

1. Attorney General

For numerous reasons, the Attorney General argues that the use of ratepayer funds to support the T&I programs proposed by National Grid should be rejected (Attorney General Brief at 207-208). First, the Attorney General contends that the Companies have failed to demonstrate that the T&I projects will benefit customers, as evidenced by National Grid's difficulty in developing cost-benefit analyses for many of the projects (Attorney General Brief at 208, citing Tr. 7, at 1005). Second, the Attorney General claims that National Grid's proposal is more expensive than the research and development surcharge rejected by the Department in D.T.E. 03-40 and higher than the surcharges National Grid currently imposes on customers in other jurisdictions for similar types of programs (Attorney General Brief at 208-209, citing Exh. AG-DED-1, at 66).

Third, the Attorney General argues that the T&I proposal fails to meet the standards set by the Department in D.T.E. 03-40, when it rejected Boston Gas' proposed research and development program (Attorney General Brief at 209, citing D.T.E. 03-40, at 428-430). In particular, the Attorney General asserts that although the Companies propose to fund the T&I programs solely with ratepayer funds, any benefits from the programs also will flow to customers of other gas companies, both within and outside of Massachusetts (Attorney General Brief at 210, citing Tr. 7, at 927; Attorney General Reply Brief at 83). Further, the Attorney General notes that National Grid, in developing the proposed T&I programs, failed to discuss the collaboration of research activities and funding with other Massachusetts gas companies, despite clear Department precedent requiring such collaboration (Attorney General Brief at 210-211, citing D.T.E. 03-40, at 429-430, Tr. 7, at 873-874, 879; Attorney General Reply Brief at 82-83).

Fourth, the Attorney General argues that a significant number of the individual projects proposed by National Grid are better suited for consideration as part of the Companies' energy efficiency plan (Attorney General Brief at 211). The Attorney General contends that the approval of funding for energy efficiency measures in this proceeding would lead to less stringent oversight of the projects than if they were considered as part of National Grid's energy efficiency plan (Attorney General Brief at 212).

Fifth, the Attorney General contends that the proposed T&I programs are based on highly speculative expenditures and benefits (Attorney General Brief at 212-213). The Attorney General disputes National Grid's assertion that a large number of the proposed projects are near-commercial development and, instead, argues that the programs have a pure research component with speculative benefits (Attorney General Brief at 212-213, citing Exhs. NG-SB-3, at 20, NG-SB-4; Attorney General Reply Brief at 82).

Sixth, the Attorney General argues that the T&I proposal is an inappropriate attempt to have ratepayers subsidize load growth through the use of natural gas-based technologies (Attorney General Brief at 213). The Attorney General asserts that ratepayers should not be responsible for promoting new natural gas end-uses in industries such as transportation (Attorney General Brief at 213). Moreover, the Attorney General contends that the T&I proposal runs contrary to the Department's decoupling policy of reducing natural gas load growth through energy efficiency (Attorney General Brief at 214, citing Tr. 6, at 826-827).

Finally, the Attorney General argues that the Companies do not need a ratepayer-funded T&I program to address the challenges National Grid identifies (Attorney General Brief at 215). The Attorney General disputes National Grid's claim that the current economic environment has made it difficult to maintain research and development funding (Attorney General Brief at 215, citing Exh. NG-SB-1, at 12). In particular, the Attorney General notes that the record demonstrates that between 2006 and 2008, venture capitalists invested over $1.2 billion in clean energy in Massachusetts, second only to California (Attorney General Brief at 215, citing Exh. NG-SB-2, at 54). Further, the Attorney General notes that Massachusetts ranks in the top ten in all but one of the new clean energy technologies identified by the Companies (Attorney General Brief at 215). In addition, the Attorney General contends that the U.S. Department of Energy's congressional budget for energy efficiency and renewable energy in Massachusetts is expected to grow from $5.7 million to $8.3 million in 2011 and that $24.5 billion in general research and development support[107] will flow to Massachusetts in 2011, second only to California (Attorney General Brief at 215-216, citing Exh. AG-DED-1, at 74).

2. ENE

ENE argues that the Department should reject National Grid's T&I proposal because it is inconsistent with the Department's directives in D.T.E. 03-40 and the intent of the Green Communities Act (ENE Brief at 11-12). In particular, ENE submits that National Grid failed to follow Department precedent set forth in D.T.E. 03-40 to collaborate with other Massachusetts local gas distribution companies in developing its proposed T&I program (ENE Brief at 12 & n.45, citing Tr. 6, at 877). ENE argues that the transportation-related programs contained in the T&I proposal should be addressed through a coordinated statewide effort (ENE Brief at 14).

Further, with respect to the Green Communities Act, ENE contends that the energy efficiency programs proposed by National Grid are better suited for consideration as part of the Companies' three-year energy efficiency plan (ENE Brief at 12-13). ENE asserts that the process established by the Department to review and approve energy efficiency plans is the most effective means of implementing and funding energy efficiency-related programs (ENE Brief at 13).

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107 This amount includes research and development funding directed to business, universities, federal agencies, and non-profit entities (Exh. AG-DED-16).

Finally, ENE asserts that it is not appropriate for National Grid to request ratepayer funding for transportation projects if such programs will not directly benefit the Companies' heating customers (ENE Brief at 14). ENE disputes as speculative National Grid's assertion that the promotion of compressed natural gas ("CNG") transportation is beneficial to gas heating customers because at some future point, under the right circumstances, gas customers may experience lower utility bills (ENE Brief at 14).

3. National Grid

National Grid argues that its proposed T&I programs should be approved because the projects will produce quantifiable benefits for its Massachusetts gas customers in the form of reduced energy usage and lower energy bills (through increased-efficiency appliances and equipment), increased safety, enhanced reliability, cost containment, and a reduction of greenhouse gas emissions (Exh. NG-SB-1, at 2-3, 5-6, 8; National Grid Brief at VI.1). In this regard, National Grid contends that annual customer benefits will be approximately $26.7 million, arising primarily from customer-related energy cost savings (Exhs. NG-SB-1, at 8; NG-SB-4; National Grid Brief at VI.4). Further, National Grid argues that the development of renewable gas technology has the potential to produce 400 to 1,300 new jobs in Massachusetts (Exh. NG-SB-1, at 6-7, 9; National Grid Brief at VI.1).

In addition, National Grid argues that the proposed T&I surcharge is not excessive (National Grid Brief at VI.7). According to National Grid, the total cost of the proposed T&I projects amounts to 0.25 percent of the Companies' sales, a ratio similar to its surcharge levels for comparable programs in New York and the United Kingdom (National Grid Brief at VI.7, citing Exh. NG-SB-1, at 8-9). Moreover, National Grid submits that it has developed internal controls to ensure that funds recovered from customers for the T&I programs are spent effectively (Exh. NG-SB-1, at 10). More specifically, National Grid contends that, based on its experience with similar programs in New York and the United Kingdom it has: (1) designed the programs to ensure that funds collected are only used for the T&I programs; (2) established a clear mission for the programs with a discreet scope of potential activities; (3) ensured transparency through annual reporting and oversight by the Department of all stages of the process;[108] and (4) proposed a multi-year program to enable it to make long-term commitments to projects and partners (Exh. NG-SB-1, at 10; National Grid Brief at VI.2).

Further, National Grid argues that its T&I proposal addresses all concerns raised by the Department in prior proceedings, most notably D.T.E. 03-40 (National Grid Brief at VI.4-5). In particular, National Grid submits that the proposed surcharge is not duplicative of any federal surcharges as the federal interstate pipeline surcharge supporting gas industry research and development has been eliminated (National Grid Brief at VI.5).

In addition, as required by D.T.E. 03-40, National Grid contends that it has demonstrated that the proposed projects have positive benefit-to-cost ratios (National Grid Brief at VI.5, citing Exh. NG-SB-1, at 7-8; National Grid Reply Brief at 59-60). Therefore, National Grid asserts that the T&I proposal differs from other research and development funding mechanisms where projects may be worthwhile but benefits are speculative (National

[108] National Grid notes that its proposal requires the Department's approval of specific projects prior to their implementation (National Grid Brief at VI.5, citing Tr. 7, at 921-922; National Grid Reply Brief at 60).

Grid Brief at VI.6). National Grid argues that, contrary to the Attorney General's position, its T&I proposal is not solely devoted to funding for research and development projects (National Grid Brief at VI.3; National Grid Reply Brief at 59). Instead, National Grid contends that its proposed T&I programs focus on promising technologies that have progressed far enough in specific applications to demonstrate substantial and quantifiable cost savings and benefits to ratepayers (National Grid Brief at VI. 3-4, citing Exhs. NG-SB-1, at 15, NG-SB-4, Tr. 6, at 878; National Grid Reply Brief at 59). According to National Grid, the proposed T&I programs represent the "middle ground" between threshold concepts that are studied and validated in academic and industry research and market trials or pilots that typically precede the successful roll-out of proven new technologies (National Grid Reply Brief at 59).

Further, National Grid submits that because a net benefit to its ratepayers can be reasonably assured through the careful selection of projects, the lack of collaboration among other Massachusetts gas companies is inapposite (National Grid Brief at VI.6-7; National Grid Reply Brief at 60).[109] Nevertheless, National Grid notes that, in order to ensure that costs are shared among the greatest base of like-minded companies and customers, it has worked collaboratively with local gas distribution companies across the United States that share National Grid's perspective on implementing T&I solutions (National Grid Brief at VI.6; National Grid Reply Brief at 60, citing Tr. 6, at 873-875, 880-881).

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109 In this regard, National Grid questions why it is a relevant consideration that other gas utilities should benefit from the Companies' efforts if withholding funding for such projects would also deny the benefits to the Companies' customers (National Grid Brief at VI.6 n.1).

National Grid also submits that its T&I proposal is not inconsistent with the goals of Green Communities Act with respect to energy efficiency (National Grid Brief at VI.8). Specifically, National Grid disputes the Attorney General's contention that growth in overall customer load is a goal of its T&I proposal (National Grid Brief at VI.8). Moreover, National Grid argues that increases in natural gas load as a result of fuel switching reduces carbon emissions and other greenhouse gases and, therefore, is entirely consistent with the Commonwealth's overall energy goals (National Grid Brief at VI.8).

Similarly, National Grid disputes any assertion that the T&I proposal is inconsistent with the Department's decoupling objectives (National Grid Brief at VI.8). According to National Grid, fuel switching that results from its T&I programs is not unnecessary consumption but rather a rational and economic substitution (National Grid Brief at VI.8-9). Finally, National Grid disputes the Attorney General's contention that the Companies only would seek to add customers whose usage would be less than existing customers in order to drive down average use per customer and earn a decoupling surcharge (National Grid Brief at VI.9). According to National Grid, the Companies have little control over the size of applications by new customers and, therefore, have no ability to inappropriately influence average use per customer (National Grid Brief at VI.9).

C. Analysis and Findings

National Grid proposes to implement two new programs (a gas operations program and an end-use/renewables program) with a focus on technology and innovations in the areas of asset protection, environmental protection, operations improvement, advanced energy efficiency, clean transportation, and renewable gas (Exhs. NG-SB-1, at 7; NG-SB-3, at 2-4, 5-22). The Companies state that the T&I proposal is designed to address several business challenges including the development of strategies to: reduce operating costs; maintain the safety and reliability of the distribution system; lower customer energy bills; address climate change issues; and aid in job development (Exh. NG-SB-1, at 4). Arguing that its customers will be the main beneficiaries, National Grid proposes that ratepayers fund the T&I programs through an annual surcharge of $4.7 million (Exh. NG-SB-1, at 9). The Department has examined National Grid's T&I proposal and, for the reasons discussed below, we do not approve the proposed surcharge.

The benefits of National Grid's T&I proposal are far from clear. Although National Grid argues that the annual customer benefits of the programs will be approximately $26.7 million, the record demonstrates that expected benefits of the T&I proposal are speculative and difficult to discern (Exhs. DPU-8-11; DPU-8-13; Tr. 6, at 829-832, 836, 841, 847-848, 854-855).[110] The proposed list of projects is not final and National Grid states that it

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[110] For example, National Grid accepts that it needs to perform additional analysis to confirm whether its proposed anaerobic digestion project is cost effective (Tr. 6, at 843-846). Nonetheless, National Grid includes $2,582,620 for this project in its estimate of annual customer benefits, despite not conducting any studies to confirm the benefits (Exhs. NG-SB-4; DPU-16-18, Att.; Tr. 6, at 843-846). Also, National Grid includes significant benefits in its annual estimate from projects designed to reduce gas operations costs (see, e.g., Exhs. NG-SB-4; Tr. 7, at 961-962). However, the Companies state that these benefits would not flow to customers until National Grid's next general rate case (Tr.6, at 854-855). Further, National Grid claims $5,852,688 in annual benefits for its various advanced energy efficiency projects (Exhs. NG-SB-3; NG-SB-4; DPU-16-18). However, none of these programs is commercially available or cost effective (Exhs. DPU-8-11; DPU-8-22; DPU-8-23). See also D.P.U. 08-50, at 15-18.

will conduct a cost/benefit analysis on an annual basis to review the costs and benefits of the T&I programs (Tr. 6, at 836, 867, 872). However, the Department cannot approve an annual expenditure of $4.7 million in ratepayer funds without more concrete proof that the Companies' ratepayers will see equal or greater benefits. See D.T.E. 03-40, at 429.

Further, while some of the activities proposed by National Grid could ultimately provide value to National Grid and its ratepayers, the proposed T&I surcharge is not the appropriate way to recover these costs. First, a number of the Companies' proposed T&I projects involve gas research and development costs. However, National Grid has failed to adhere to the Department's directives to collaborate with other local gas distribution companies with respect to proposals for gas research and development funding. D.T.E. 03-40, at 429-430. The Department rejected a similar research and development surcharge proposal made by Boston Gas in D.T.E. 03-40.[111] The Department stated in D.T.E. 03-40, at 429-430

111 As part of its last rate case, Boston Gas proposed to establish a surcharge to support gas research and development efforts. D.T.E. 03-40, at 425. Boston Gas did not seek approval of specific research and development programs in D.T.E. 03-40 and, instead, offered to submit proposed programs for Department review following approval of the surcharge. D.T.E. 03-40, at 426. The Department rejected Boston Gas' proposal for several reasons. First, the Department concluded that there was insufficient proof that the surcharge would benefit Boston Gas customers. D.T.E. 03-40, at 428-429. Second, the Department was concerned about double collecting by Boston Gas because the customer surcharge would be effective before the expiration of a related federal surcharge ended. D.T.E. 03-40, at 429. Third, the Department found it was not appropriate to approve a surcharge to customers without first approving the specific research and development proposals that the surcharge was intended to fund. D.T.E. 03-40, at 429. Finally, the Department found that the role of research and development efforts in Massachusetts was a matter of concern to numerous affected parties and, therefore, the merits of any research and development funding need to be considered in a broader investigation involving all Massachusetts local distribution companies. D.T.E. 03-40, at 429-430.

that the merits of any gas research and development funding and a mechanism for cost recovery should be considered in a broader investigation involving all Massachusetts local gas distribution companies. However, while National Grid collaborated with "like minded" utilities in the United Kingdom and Japan, it neglected to discuss the T&I proposal with the other Massachusetts local gas distribution companies – purportedly because it did not see representatives of these companies at T&I-related conferences and meetings (Tr. 6, at 880).[112] Such collaboration clearly does not meet the standards articulated by the Department in D.T.E. 03-40, at 429-430 for consideration of gas research and development funding.

In addition, under National Grid's T&I proposal, customers would be paying for asset protection and operations improvement programs providing asserted benefits not just for themselves but for National Grid's shareholders. For example, a review of the projects listed under "protection of assets" shows that National Grid stands to benefit from these projects[113] (Exh. NG-SB-4). Once rates are set in the instant case, the benefit of reduced operating costs will flow to the Companies' shareholders and not its customers until the next rate case filing

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112 The Department notes that National Grid is a member of GasNetworks, a collaborative of local gas distribution companies in Massachusetts and New England whose mission is to promote energy efficient technologies, create common energy efficiency programs, educate consumers and promote contractor training and awareness of ever-changing natural gas technologies. GasNetworks About Us Overview, http://www.gasnetworks.com/about/index.asp. However, National Grid did not discuss any aspects of its T&I proposal with the other members of the GasNetworks collaborative (Tr. 6, at 872-874).

113 Projects with clear shareholder benefits include: damage prevention; pipe location; integrity management; and improved materials, standards, and repair (Exh. NG-SB-4). National Grid has an obligation to address safety risks and leak reduction and should not require a separate funding mechanism to perform these tasks.

(Tr. 6, at 854-855, 861). Therefore, it is not appropriate to include such programs as part of a T&I surcharge proposal.

Finally, we find that the proposed energy efficiency projects should not have been included in the Companies' T&I proposal. Projects designed to improve energy efficiency or developed to commercialize energy-efficiency equipment must be reviewed within the regulatory structure set forth in the Green Communities Act and the Department's energy efficiency guidelines established in Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50 (2008); D.P.U. 08-50-A (2009); D.P.U. 08-50-B (2009) ("Guidelines") Guidelines § 2(11); see G.L. c. 25, §§ 19-21, G.L. c. 25A § 11G. If National Grid wishes to pursue such projects, they must be considered as part of the Companies' energy efficiency plan.[114]

Accordingly, for the reasons discussed above, we decline to approve National Grid's T&I proposal and proposed T&I surcharge.

VIII. RATE BASE

A. Plant Additions

1. Introduction

National Grid reported a total plant in service as of the end of the test year for Boston Gas-Essex Gas of $2,611,670,845 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 43;

[114] In the event that any projects are not yet cost effective, the Department notes that National Grid has the option to propose that they be conducted as either pilot programs or hard-to-measure energy efficiency programs. D.P.U. 08-50-A at 30-31.

DPU-12-21). The Companies reduced total plant in service by $400,324,968 to recognize the elimination of: (1) $394,547,102 in goodwill; (2) $1,914,407 in asset retirement obligations; (3) $3,795,608 representing Boston Gas plant that had been excluded from rate base in that company's previous rate proceeding, D.P.U. 03-40; and (4) $67,851 associated with a growth-related project on Old Neck Road in Manchester, Massachusetts ("Old Neck Road") that was placed into service by Essex Gas during 2009 and that the Companies determined to have failed to achieve its targeted rate of return (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 44; DPU-12-5, Att. 4, at 3; Tr. 13, at 1693-1694).[115]

In the case of Colonial Gas, National Grid reported a total plant in service as of the end of the test year of $794,373,106 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 42). The Companies reduced Colonial Gas' total plant in service by $199,611,497 to recognize the elimination of: (1) $199,000,465 in goodwill; (2) $579,812 in asset retirement obligations; and (3) $31,220 associated with a parcel of land deemed to be unrelated to utility operations (Exh. NG-MDL-2-Colonial (Rev. 3) at 43).[116]

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115 In recognition of these adjustments, National Grid reduced its accumulated depreciation reserve by: (1) $1,895,434 in depreciation associated with asset retirement obligations; (2) $828,384 in depreciation associated with the plant that had been excluded from rate base in D.T.E. 03-40; and (3) $836 in accumulated depreciation associated with Old Neck Road (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 44).

116 In recognition of these adjustments, National Grid reduced Colonial Gas' accumulated depreciation reserve by $571,439 to remove the accumulated depreciation associated with asset retirement obligations (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 43).

2. Capital Project Documentation

National Grid classifies its utility plants into two categories: (1) non-growth plant associated with activities necessary to maintain system safety and reliability; and (2) growth-related related plant associated with new customers or increased load (Tr. 13, at 1764-1765; 1778).[117] As part of its initial filing, National Grid identified 1,075 non-growth capital projects placed in service by Boston Gas from January 1, 2003 through December 31, 2009 with costs of $100,000 or greater (Exhs. NG-AS-1, at 4; NG-AS-2).[118] The Companies identified the project number, ACE code,[119] street address and town, description, pre-construction cost estimate, post-construction actual cost, and project dollar and percent variances of estimated cost versus actual cost (Exhs. NG-AS-1, at 4; NG-AS-2).

Similarly, National Grid provided a list of 138 growth-related capital projects placed in service by Boston Gas from January 1, 2003, through December 31, 2009, with costs of $100,000 or greater (Exhs. NG-AS-1, at 4-5; NG-AS-5).[120] In addition to the above-listed set

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117 Non-growth plant is also referred to as non-revenue producing plant, while growth related plant is also referred to as revenue producing plant. See D.T.E. 05-27, at 68; D.T.E. 03-40, at 40, 63.

118 Boston Gas' last rate case was in 2003, based on a 2002 test year. See D.T.E. 03-40.

119 ACE codes are a system of segregating National Grid's capital expenditures; there are 23 separate ACE codes, each of which represents a specific category of work (Exh. DPU-12-1). For example, ACE 101C designates mains for new commercial customers, ACE 101R designates mains for new residential customers, ACE 103(CI) designates mains relay street construction (cast iron), and ACE 103(ST) designates main relay condition (steel) (Exh. DPU-12-1).

120 National Grid identified capital investments made for mains and services in excess of $100,000 to be consistent with the threshold that was used in D.T.E. 03-40.

of information provided for non-growth projects, National Grid provided for each growth-related project the pre-construction and post-construction internal rate of return ("IRR") (Exhs. NG-AS-1, at 4-5; NG-AS-5, at 1-13).

For Essex Gas, National Grid identified 83 non-growth and 39 growth-related projects placed in service from January 1, 2001, through December 31, 2009, with costs of $50,000 or greater and provided pre-and post-construction IRRs for the growth-related projects (Exhs. NG-AS-1, at 4-5; NG-AS-3; NG-AS-6).[121] For Colonial Gas, National Grid identified 249 non-growth and 119 growth-related projects placed in service from January 1, 2001, through December 31, 2009, with costs of $50,000 or greater,[122] and provided pre-and post-construction IRRs for the growth-related projects (Exhs. NG-AS-1, at 4-5; NG-AS-4; NG-AS-7).[123]

National Grid provided capital authorization and closing reports for: (1) Boston Gas from January 1, 2003, through December 31, 2009, for all projects costing $100,000 or greater; (2) Essex Gas from January 1, 2001, through December 31, 2009, for all projects

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121 Essex Gas' last rate case was in 1996, based on a 1995 test year. See D.P.U. 96-70.

122 In the case of Essex Gas and Colonial Gas, National Grid used a threshold of capital project costs in excess of $50,000 because, during the time period at issue, there were relatively few projects costing in excess $100,000 (Exh. NG-AS-1, at 4).

123 Colonial Gas' last rate case was in 1993, based on a 1992 test year. See D.P.U. 93-78.

costing $50,000 or greater; and (3) Colonial Gas from January 1, 2001 through December 31, 2009 for all projects costing $50,000 or greater (Exh. AG-1-19, Att.).[124]

During the proceeding, National Grid revised its lists of non-growth and growth-related plants for Boston Gas, Essex Gas, and Colonial Gas (Exh. DPU-12-5, Atts.).[125] Specifically, National Grid provided: (1) information as to whether the growth-related project is discretionary or non-discretionary; (2) cross-references to every project code and the respective supporting street mains authorization ("SMA") or work order, compatible unit estimates ("CUE"),or closing reports filed as part of the Companies' prior document production; (3) updates and corrections to previously-filed SMAs and closing reports, plus additional SMAs and closing reports that were not included in earlier document production; and (4) a variance analysis for Boston Gas, Essex Gas, and Colonial Gas, for each non-growth project where actual project costs were 15 percent or more than the original estimates (Exhs. NG-AS-2 (Rev.); NG-AS-3 (Rev.); NG-AS-4 (Rev.); DPU-12-3; DPU-12-5, Atts. 2, 4, 6; DPU-12-7;

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124 National Grid filed 14 volumes containing the capital authorization and closing reports for the above-listed projects (Exh. AG-1-19, Att. Book 1 through Book 14, bates stamp pages 1 through 9,065). Exhibit AG-1-19 includes National Grid's responses to: (1) information request AG 1-19, which requested for the capital authorization and closing reports for all projects of Boston Gas begun or finished since January 1, 2003 costing $50,000 or more; (2) information request AG 2-19, which requested for the capital authorization and closing reports for all projects of Essex Gas begun or finished since January 1, 1996 costing $50,000 or more; and (3) information request AG 3-19, which requested for the capital authorization and closing reports for all projects of Colonial Gas begun or finished since January 1, 1993 costing $50,000 or more.

125 National Grid indicated that the attachments to exhibits DPU-12-5-1 through DPU-12-5-6 represent revisions to exhibits NG-AS-2 through NG-AS-7, respectively (Exhs. DPU-12-5, at 2; DPU-12-8; DPU-12-9; DPU-12-11; RR-DPU-94).

DPU-12-8; DPU-12-8, Atts. 2-11.4; DPU-12-10 (Rev.) Atts. BOS Non-Growth; ESX Non-Growth; COL Non-Growth).[126] National Grid also provided variance analyses for each project identified in its revised list of growth-related plant for Boston Gas, Essex Gas and Colonial Gas (Exhs. DPU-12-5, at 2; DPU-12-12 (Rev.) Atts. BOS Growth; ESX Growth; COL Growth).[127]

The information provided by National Grid did not include plant additions made by Essex Gas from January 1, 1996, to December 31, 2000, or for Colonial Gas from January 1, 1993 through December 31, 2002 (AG-1-19, Atts.). Consequently, the Department requested that National Grid supplement its earlier document production (i.e., exhibit AG 1-19) to

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[126] Non-growth related plant, such as the replacement of cast iron mains, may be fairly characterized as non-discretionary because a company is obligated to maintain the integrity of the distribution system and comply with safety standards. D.T.E. 03-40, at 67. On the other hand, for other types of projects (e.g., replacement of a customer information system or construction of a water treatment plant), a company has a measure of discretion, in that the company can select from among a number of options the most cost-effective means of meeting the company's operational needs. D.T.E. 03-40, at 67; see also D.P.U. 95-118, at 43-45.

[127] National Grid's variance analysis for each project shows, among other things, the project number, ACE code, location, estimated and actual direct project costs, estimated and actual "loaded" (labor overhead and clearing account burden) costs, dollar and percent variances in direct and loaded costs, and list of components of direct and loaded costs (Exhs. DPU-12-10 (Rev.) Atts. BOS Non-Growth; ESX Non-Growth; COL Non-Growth; DPU-12-12 (Supp), Atts. BOS Growth; ESX Growth; COL Growth).

For the non-growth related projects, National Grid performed variance analyses for 569, 63, and 49 projects for Boston Gas, Essex Gas, and Colonial Gas, respectively (Exhs. DPU-12-10 (Rev.) Atts. BOS Non-Growth; ESX Non-Growth; COL Non-Growth). For the growth projects, National Grid performed variance analyses for 107, 28, and 43 projects for Boston Gas, Essex Gas, and Colonial Gas, respectively (DPU-12-12 (Rev.) Atts. BOS Growth; ESX Growth; COL Growth).

include work orders and closing reports of at least $50,000 for Colonial starting January 1, 1993, through December 31, 2000, and for Essex starting January 1, 1996, through December 31, 2000 (RR-DPU-74).[128]

In response, the Companies were able to identify and provide documentation for ten growth-related projects and 17 non-growth projects exceeding the $50,000 threshold for Colonial Gas, as well as for six growth-related projects and 23 non-growth projects exceeding the $50,000 threshold for Essex Gas, during 1999 and 2000 (RR-DPU-74, Att. A).[129] The Companies also located work order authorizations and closing reports for the period 1993 through 1998 for Colonial Gas that had been submitted to the Department as part of the Department's investigation in D.T.E. 98-128 (RR-DPU-74(B) [BULK]). The Companies stated that they were unable to locate any additional documentation relative to Essex Gas' plant additions made between 1996 and 1998 (RR-DPU-74).

128 The Attorney General objected to record request DPU-74, on the grounds that: (1) she had previously sought this identical information from National Grid, only to be told that the information did not exist; and (2) that any information that might be found would be untimely given the constraints of the procedural schedule and suspension date (Tr. 13, at 1758-1759). The hearing officer overruled the Attorney General's objection.

129 Pursuant to the ground rules issued in this case, National Grid's response to record request DPU-74 was due five days after issuance, or on July 27, 2010 (Tr. 13, at 1851). However, National Grid did not respond to this record request until August 19, 2010 – or two business days prior the date intervenors' initial briefs were due on August 23, 2010 (RR-DPU-74).

3. Positions of the Parties

a. Attorney General

The Attorney General states that Boston Gas provided sufficient evidence for its major capital additions starting in 2003, so that the Department could properly review those additions (Attorney General Brief at 101-102). More specifically, the Attorney General states that in response to discovery, National Grid provided capital authorization forms and closing reports for Boston Gas' projects costing $100,000 or greater from January 1, 2003 through December 31, 2009 (Attorney General Reply Brief at 43, citing Exh. AG-1-19). The Attorney General did not raise any issue on the capital additions of Boston Gas from 2003 through 2009.

For Colonial Gas and Essex Gas, however, the Attorney General claims that National Grid failed to properly document some of their capital additions since their last respective rate cases (Attorney General Brief at 99). The Attorney General contends that in order to collect costs from ratepayers for capital additions, the Companies have the burden of proof as to the reasonableness and prudence of capital additions (Attorney General Reply Brief at 41, citing Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967)). The Attorney General notes that prudence must be shown by a preponderance of the evidence and that the Companies cannot do so when evidence has not been provided (Attorney General Reply Brief at 44, citing D.T.E. 03-40, at 52; D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7).

First, in the case of Colonial Gas, the Attorney General notes that its last base rate case was D.P.U. 93-78 with a test year ending December 31, 1992 (Attorney General Brief at 102).

The Attorney General, however, claims that Colonial Gas provided capital additions information only going back to 2001 and failed to provide any capital addition information for each of the years 1993 through 2000 (Attorney General Brief at 102). The Attorney General notes that during this eight-year period, Colonial made $216.7 million in capital additions (Attorney General Brief at 102). The Attorney General contends that while those capital additions may be providing service to customers, National Grid has not provided any evidence that those plant additions were prudent (Attorney General Brief at 102).

The Attorney General argues that the Department should either deny the recovery of all the costs of the capital additions because Colonial Gas has no evidence to support their reasonableness or, as an alternative, allow the recovery of the investment without allowing any recovery of a return on the investment (Attorney General Brief at 102). The Attorney General argues that this later treatment would afford Colonial Gas recovery of the investment through the depreciation on the capital additions for the period 1993 through 2000 but would remove the additions to the plant in service item in the rate base calculation and the associated accumulated depreciation thereby eliminating the return on the capital additions (Attorney General Brief at 102).

Second, in the case of Essex Gas, the Attorney General claims that National Grid provided capital additions information going back only to 2001, although its last base rate case was in D.P.U. 96-70 with a test year ending December 31, 1995 (Attorney General Brief at 102). The Attorney General claims that from 1996 through 2000, Essex Gas made $28.9 million in capital additions but failed to provide any capital addition information for each of those five years as evidence that those plant additions were prudent (Attorney General Brief at 102). The Attorney General contends that, similar to Colonial Gas, the Department should deny the recovery of all the costs of the capital additions because Essex Gas has provided no evidence to support their reasonableness or, as an alternative, allow the recovery of the investment without allowing any recovery of a return on such investment (Attorney General Brief at 103). The Attorney General explains that this treatment would afford Essex Gas recovery of the investment through the depreciation on the capital additions for the period 1996 through 2000 but would remove the additions to the plant in service item of the rate base calculation and the associated accumulated depreciation, thereby eliminating the return on the capital additions (Attorney General Brief at 103).

In addition, the Attorney General questions the treatment of National Grid's production of certain documents related to Essex Gas' and Colonial Gas' historical capital conditions (Attorney General Reply Brief at 41-45, citing RR-DPU-74).[130] The Attorney General notes that when National Grid was first asked to produce the documents at issue early in the discovery process in this proceeding, National Grid indicated that: "As a result of the various company consolidations and the changes in record keeping systems that have occurred over time, work orders for Essex Gas Company and Colonial Gas Company prior to 2001 are not available" (Attorney General Reply Brief at 43, citing Exh. AG-1-19). However, much later

130 Record request DPU-74 asked National Grid to revise its response to information request AG-1-19 to include work orders and closing reports of at least $50,000 for Colonial Gas starting January 1, 1993, through December 31, 2000, and for Essex Gas starting January 1, 1996, through December 31, 2000 (RR-DPU-74).

in the proceeding, on the day before initial briefs were due, the Attorney General states that National Grid produced additional documents that it earlier stated were not available (Attorney General Reply Brief at 41, 44, citing RR-DPU-74). Because National Grid did not produce information until the day before initial briefs were due, it was impossible for any party to cross-examine the Companies about cost overruns or any other issues regarding prudence (Attorney General Reply Brief at 41, 44).[131] The Attorney General asserts that the late production of these additional documents contravenes the due process requirements of the Administrative Procedure Act, which provides all parties the right to call and cross-examine witnesses (Attorney General Reply Brief at 42, 44-45 citing G.L. c. 30A, § 11(3)). The Attorney General claims that the Department has previously warned Boston Gas about the requirement to provide supporting evidence for capital additions (Attorney General Reply Brief at 42, citing D.T.E. 03-40, at 48, 52). Accordingly, the Attorney General argues that National Grid's "stonewalling cannot be rewarded" because inquiries about over-runs, variances, overheads, and prudence of millions of dollars in rate base additions went unexamined (Attorney General Reply Brief at 42). Because such rate base additions cannot be reviewed for reasonableness and prudence, the Attorney General argues that they should be rejected in their entirety (Attorney General Reply Brief at 44, citing D.P.U. 92-210-C, at 17).

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131 Responses to record requests are written substitutes to oral answers where fault of memory or complexity of subject precludes a responsive answer by the witness at the hearing. 220 C.M.R. § 1.06(h). As such, they are part of the evidentiary record, unless challenged as unresponsive and stricken in whole or in part. Record requests shall not be used as a substitute for discovery or as a substitute for re-direct examination.

b. National Grid

National Grid claims that over the past 20 years, the Department has developed a detailed and prescriptive standard for the inclusion in rate base of capital projects undertaken by a gas company between rate cases and that the Companies have met that standard (National Grid Brief at IX.5). According to National Grid, at the core of the Department's standard is the recognition that not all projects completed by a company in a given year are of the same scope and magnitude (National Grid Brief at IX.5-6, citing D.T.E. 03-40, at 31-82; D.P.U. 96-50 (Phase I), at 21-23). The Companies therefore maintain that the level of documentation that is required to support the inclusion of capital additions must be "commensurate" with the project's cost and complexity (National Grid Brief at IX.5, citing D.T.E. 05-27, at 68-97; D.T.E. 03-40, at 31-82; D.P.U. 96-50 (Phase I) at 21-23; Boston Gas Company, D.P.U. 93-60, at 24-26 (1993)). National Grid claims that Department ratemaking practice specifies that the threshold for submission of detailed project documentation is $100,000 for larger companies and $50,000 for smaller companies (National Grid Brief at IX.6, citing D.P.U. 09-30; D.P.U. 08-35; D.T.E. 05-27, at 68).

In this regard, National Grid claims that it has submitted the required documentation covering the period from 1993 through 2000 for Colonial Gas (National Grid Brief at IX.7, citing RR-DPU-74). National Grid claims that it produced work order authorizations and closing reports for the period 1993 through 1998 for Colonial Gas, including documentation for ten growth-related projects and 17 non-growth projects exceeding the $50,000 threshold

(National Grid Brief at IX.7-8, citing RR-DPU-74, Atts. C-1, C-2).[132] In the case of Essex Gas, National Grid claims that it has identified and provided documentation for six growth-related projects and 23 non-growth projects exceeding the $50,000 threshold for the period 1999 to 2000 (National Grid Brief at IX.8, citing RR-DPU-74, Att. A). National Grid states that it was unable to locate project documentation for Essex Gas for projects in the period 1996 through 1998, despite significant efforts to retrieve this information (National Grid Brief at IX.8).

National Grid acknowledges that it bears the burden of providing reviewable documentation for the investments that it seeks to include in rate base (National Grid Brief at IX.8, citing D.P.U. 92-210, at 24 (1993); Massachusetts Electric Company, D.P.U. 95-40, at 6-7 (1995)). National Grid, however, claims that the documentation requirements established by the Department are designed to provide a basis for evaluating a utility's proposals and for rendering a decision as to the prudence of the utility's actions in incurring costs that are proposed for recovery, not to stand as a separate basis for cost disallowance (National Grid Brief at IX.8-9, citing D.T.E. 03-40, at 67-68 (2003). Accordingly, National Grid argues that the lack of project documentation does not necessarily require disallowance of cost because the lack of documentation itself does not prove imprudence, it only makes it difficult to demonstrate prudence (National Grid Brief at IX.9).

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132 As part of its response to record request DPU-74, National Grid provided a copy of exhibit CG-1-24 (BULK), which provides project documentation for the period 1993 through 1998 for Colonial Gas, and was part of the evidentiary record in D.P.U. 98-128 (RR-DPU-74(A)).

Further, National Grid argues that the Department has recognized that, given the length of time between rate cases and the system conversions that have occurred in the intervening time period, historical project documentation may not be available for projects completed some time ago – or may be available in formats that are incompatible with current data information systems (National Grid Brief at IX.9, citing D.P.U. 09-39).[133] National Grid claims that it has met its burden in this case because it has submitted project documentation for twelve years for Essex Gas and 17 years for Colonial Gas, which it contends represents virtually all of the documentation required under the Department's standard (National Grid Brief at IX.9).

In responding to the Attorney General's argument relating to late filed information, National Grid notes that, early in the proceeding, it submitted approximately 14,000 pages of documentation relating to 1,701 growth-related and non-growth capital projects for Boston Gas, Colonial Gas, and Essex Gas for the period 2001 through 2009 (National Grid Reply Brief at 91-92, citing Exhs. AG-1-19; AG-2-19; AG-3-19).[134] National Grid claims that, at the

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133 National Grid claims that, for example, the Department reviewed and approved capital additions to rate base for the period 2000 to 2008 for National Grid's electric operations in D.P.U. 09-39, although the most recent rate case had occurred in 1995 (National Grid Brief at IX.9, citing D.P.U. 09-39, at 97-101.

134 National Grid states that, in preparing this case, it devoted a team of people generating comprehensive project documentation, including work order authorization, closing reports and variance reports, for Boston Gas, Colonial Gas and Essex Gas for the ten-year period prior to its rate case filing on April 16, 2010 (National Grid Reply Brief at 92-93 citing Tr. 13, at 1751-1758). National Grid states that it reviewed old files and archives, and conducted a diligent effort to produce the required documentation (Tr. 13, at 1754). National Grid states that the documentation prior to 2001 could not initially be produced because of mergers, subsequent system changes and differing standards for recordkeeping in the years prior to 2001, which primarily involved manual recordkeeping (National Grid Reply Brief at 93, citing Tr. 13, at 1752, 1754,

evidentiary hearings, the Attorney General inquired into only nine projects, all of which were on the Boston Gas system, with the sole focus being the variance in the ratio of allocated overheads and burdens to direct costs (National Grid Reply Brief at 92). National Grid claims that the Attorney General did not perform any examination on direct project costs, the prudence of costs, or any projects on the Essex Gas or Colonial Gas systems (National Grid Reply Brief at 92, citing Tr. 13, at 1726-1741).

National Grid claims that the Attorney General had ample opportunity to cross examine National Grid's witness on the Essex Gas and Colonial Gas project documentation for later projects (i.e., projects completed between 2001 and 2009) but did not take advantage of this opportunity (National Grid Reply Brief at 92). Further, National Grid asserts that the projects completed on the Colonial Gas system for the years 1993 through 1998 were already reviewed by the Attorney General in D.T.E. 98-128 when setting the cast-off revenue requirement in that case (National Grid Reply Brief at 92 n. 2, citing RR-DPU-74).

With respect to the Attorney General's assertion that the Department should find the pre-2001 projects imprudent because of the timing of the production of the documentation, National Grid asserts that this argument rests on a technicality which ignores that there is no evidence that any imprudence occurred in relation to a single project out of the 9,000 projects completed since 2001 or the 1,701 projects that exceeded the $50,000 threshold (National Grid Reply Brief at 93).

1756). However, National Grid states that it was ultimately able to produce pre-2001 information but in the format maintained prior to 2001 (National Grid Reply Brief at 93).

In conclusion, National Grid claims that it provided evidence supporting capital additions over $50,000 for Essex Gas and Colonial Gas for the years 2001 through 2009 (National Grid Brief at IX.9; National Grid Reply Brief at 94). National Grid adds that it subsequently researched, retrieved, and produced project documentation for the years 1998 through 2009 for Essex Gas and for the years 1993 through 2009 for Colonial Gas (National Grid Brief at IX.9; National Grid Reply Brief at 94). National Grid notes that in the years 1999 and 2000, there were only 29 growth-related and non-growth projects completed on the Essex Gas system with total project costs in excess of $50,000, and this figure serves as an appropriate proxy for the preceding two-year period, 1996 to 1998 (National Grid Brief at IX.9-10; National Grid Reply Brief at 94). Thus, National Grid argues that it has produced documentation for all of the projects completed on the Essex Gas system in 1996 through 2009 and on the Colonial Gas system in the period 1993 through 2009, with the exception of an estimated 30 projects completed in the years 1996 through 1998 on the Essex Gas system with total project costs exceeding $50,000, which would now have a net book value substantially diminished from original cost (National Grid Reply Brief at 94).[135] National Grid concludes that in this case, the information it produced satisfies the Department's standards for inclusion of 100 percent of the proposed capital additions in rate base for Boston Gas, Essex Gas, and Colonial Gas by: (1) demonstrating that the cost of its discretionary and non-discretionary, revenue producing and non-revenue producing projects are reasonable and prudently incurred;

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[135] National Grid claims that it has produced more documentation in this case than any other utility has ever provided in a Department proceeding, thereby warranting full recovery of the costs invested and a return on that investment (National Grid Brief at IX.10).

and (2) demonstrating that the plant in service is used and useful (National Grid Brief at IX.10; National Grid Reply Brief at 94).

4. Analysis and Findings

a. Introduction

For costs to be included in rate base the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to earn a return. D.P.U. 85-270, at 20 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 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known or reasonably should have been known at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (2003); 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 also found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 03-40, at 48; Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). The Department has stated that existing customers receive benefits whenever the return on incremental rate base exceeds the company's overall rate of return. Boston Gas Company, D.P.U. 89-180, at 16-17 (1990).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993); see also Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967). 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 (1993).

b. National Grid Adjustments to Plant Investment Balances

Department precedent requires that goodwill be removed from rate base. Boston Gas Company, D.P.U. 17138, at 7-8 (1971). Further, because asset retirement obligations constitute balance sheet entries that do not represent plant in service, the Department excludes asset retirement obligations from rate base. D.P.U. 09-39, at 102-104; see also Western Massachusetts Electric Company, D.T.E. 05-9, at 13 (2005). The Department finds that the Companies appropriately reduced total plant in service to eliminate goodwill and asset retirement obligations from rate base (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 44; NG-MDL-2-Colonial (Rev. 3) at 43).[136]

National Grid has also proposed to remove plant investment that had been previously excluded from Boston Gas' rate base, as well as the Old Neck Road project, and a parcel of land owned by Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 44; NG-MDL-2-Colonial (Rev. 3) at 43). The Department finds that National Grid has treated the excluded Boston Gas plant additions consistent with our findings in D.T.E. 03-40. See D.T.E. 03-40, at 62, 71. Moreover, the Department accepts the Companies' representations

136 In recognition of the removal of asset retirement obligations from rate base, the Department also accepts National Grid's proposed depreciation reserve adjustments associated with asset retirement obligations. See D.P.U. 09-39, at 104.

with regard to the Old Neck Road project and the Colonial Gas land parcel. Therefore, the Department accepts the Companies' proposed adjustments to rate base for these plant items.[137]

c. Capital Additions From 2001-2009

i. Direct and Overhead Variances

The variance analyses produced by Boston Gas reveal that for the 1,049 non-growth-related projects of Boston Gas between January 1, 2003, and December 31, 2009, costing at least $100,000, the variance between pre-construction estimates and final post-construction actual project costs range from a 60 percent decrease (project no. 353841) to a 1,602 percent increase (project no. 686720) (Exh. DPU-12-5, Att. 1).[138] Also, for the 164 growth-related projects of Boston Gas between January 1, 2003, and December 31, 2009, costing at least $100,000, the variance analyses indicate that changes between pre-construction estimates and

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137 In recognition of the removal of this plant from rate base, the Department also accepts National Grid's proposed depreciation reserve adjustments associated with these excluded plant additions. See D.T.E. 03-40, at 62, 71; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993).

138 Project no. 686720 was the replacement of approximately 25 feet of 4-inch, 60 pounds per square inch gauge ("psig") bare steel by a 4-inch, 60 psig coated steel on the inlet side and approximately 25 feet of 8-inch low-pressure bare steel with 8-inch of low pressure coated steel of the outlet side of a regulator on Magnolia Avenue in Lynn, Massachusetts (Exhs. AG-1-19, Book 11, at 7165-7169; DPU-12-5, Att. 1, at 57; DPU-12-10, (Rev.) Att. BOS Non-Growth). National Grid indicates that the cost variance is due to under-estimates in both direct and indirect costs (Exh. DPU-12-10, (Rev.) Att. BOS Non-Growth).

final post-construction actual project costs range from a 89 percent decrease (project no. 318423) to a 1,651 percent increase (project no. 621022) (Exh. DPU-12-5, Att. 2).[139]

With respect to Essex Gas, the variance analyses indicate that, for the 81 non-growth-related projects between January 1, 2001, and December 31, 2009, costing at least $50,000, the variance between pre-construction estimates and final post-construction actual project costs range from a 65 percent decrease (project no. 555749) to a 392 percent increase (project no. 193222) (Exh. DPU-12-5, Att. 3).[140] Also, for the 41 growth-related projects of Essex Gas between January 1, 2001, and December 31, 2009, costing at least $50,000, the variance analyses indicate changes between pre-construction estimates and final post-construction actual project costs range from a 84 percent decrease (project no. 112408) to a 180 percent increase (project no. 631404) (Exh. DPU-12-5, Att. 4).[141]

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139 Project no. 621020 related to the extension of gas main 70 feet to serve 92A Beach Street in Cohasset, Massachusetts (Exhs. AG-1-19, Book 2, at 766-770; DPU-12-5, Att. 2, at 8). National Grid explained the cost overrun was due to direct cost increases arising from paving, testing of holes, stock issues and associated loaded costs (Exh. DPU-12-12, (Rev.) Att. BOS Growth).

140 Project no. 193322 involved the installation of 2,700 feet of 6-inch plastic main relay in Summer Street, Ipswich, Massachusetts (Exhs. AG-1-19, Book 11, at 7374-7377; DPU-12-5, Att. 3, at 3). National Grid explains that the cost overrun occurred because of direct cost increases, which in turn were caused by under-estimates in the cost of materials and loaded costs (Exh. DPU-12-10, (Rev.) Att. ESX Non-Growth).

141 Project no. 631404 was for main relay on Opportunity Way, Newburyport, Massachusetts (Exhs. AG-1-19, Book 12, at 7741-7747; DPU-12-5, Att. 4, at 3). National Grid explains that the cost overrun was primarily due to direct cost increases, which in turn asset retirement obligations from under-estimates for paving and other costs, such as spoil, hoe ram, overtime, miscellaneous charges for materials and bonds, and stock issues (Exh. DPU-12-12, (Rev.) Att. ESX Growth).

In the case of Colonial Gas, the variance analyses demonstrate that, of the 243 non-growth-related projects between January 1, 2001, and December 31, 2009, costing at least $50,000, changes from pre-construction estimates to post-construction actual project costs range from a 79 percent decrease (project no. 254833) to a 912 percent increase (project no. 636495) (Exh. DPU-12-5, Att. 5).[142] Also, of the 124 growth-related projects of Colonial Gas between January 1, 2001, and December 31, 2009, costing at least $50,000, the variance analyses indicate changes from pre-construction estimates to post-construction actual project costs range from a 72 percent decrease (project no. 406347) to a 574 percent increase (project no. 312361) (Exh. DPU-12-5, Att. 6).[143]

We have reviewed National Grid's documentation for capital projects completed by the Companies between January 1, 2001, and December 31, 2009. The Department recognizes that construction estimates can vary for reasons outside of a utility's control. D.P.U. 08-35, at 25-27; D.T.E. 05-27, at 80-81. The Department's review of the supporting documentation leads us to conclude that National Grid acted prudently in estimating the costs associated with

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142 Project no. 636495 related to the replacement and lowering of 625 feet of 4-inch coated steel main with 4-inch plastic due to grade reductions as part of the Massachusetts Highway Department's street reconstruction at Cook Street and Alexander Road in Billerica, Massachusetts (Exhs. AG-1-19, Book 14, at 8856-8860; DPU-12-5, Att. 5, at 1). National Grid explains that the cost increases were primarily due to under-estimates in direct contractor and consultant costs, as well as the associated burden cost (Exh. AG-1-19, Book 14, at 8856-8860).

143 Project no. 312361 was for a new main relay on Andover Road in Billerica, Massachusetts (Exhs. AG-1-19, Book 2, at 1291-1295; DPU-12-5, Att. 6, at 4). National Grid explains that the cost overrun was primarily due to an under-estimate in materials (sand) and higher than expected gas clearing burden costs (Exh. DPU-12-12, (Rev.) Att. COL Growth).

these projects, and that the reasons for the increases in direct costs include factors that could not have been reasonably anticipated during the preparation of the construction estimates, such as the need for additional trenching and backfill, night work labor differentials, site conditions, the need to install additional mains, and government review to ensure that necessary blasting work would be safe for the neighborhood (Exh. DPU-12-10, (Rev.) Att. at 5, 6, 94, 246, 252, 442, 580, 637). There is no evidence that the underestimates in direct costs were the result of imprudence. Accordingly, we will allow these costs to be included in rate base.

Although National Grid provided sufficient and reviewable evidence including the justifications for the increases in direct costs for those projects with cost overruns, National Grid did not specifically explain the associated increases in labor overhead and clearing account burden costs (i.e., "loaded" costs) in those variance analyses (Exh. DPU-12-10 (Rev.) Att.; DPU-12-12 (Rev.)). Each year, burden and overhead rates are manually calculated for each of the Companies based on projected costs and spending (RR-DPU-82). These burdens and overheads are allocated on a monthly basis to capital projects, subject to periodic review and revision (RR-DPU-82). At the end of either the calendar or fiscal year, the burden accounts are manually adjusted, with any balances in the burden and overhead accounts at these two points in time proportionately allocated to all "open" capital projects based on the burdens that were incurred during the year (RR-DPU-82).[144] National Grid explains that

[144] For example, assuming that there are at total of ten projects anticipated in a year, each with approximately the same estimated direct cost, the burden costs would be apportioned equally (Tr. 13, at 1808). However, if only eight of those projects are completed during the construction season, the burdens associated with the two

increases in overhead and burden costs were not due to cost overruns but resulted from the potential for timing differences associated with National Grid's accounting processes, which caused an uneven allocation of capitalized labor overhead and burden costs to individual capital projects (Tr. 13, at 1829-1838; Tr. 16, at 2194; RR-DPU-82; RR-DPU-107, at 3; RR-DPU-119, at 3). National Grid states that the same timing-related reason applies for the other variance analyses where large increases in overhead and burden costs were not specifically explained (Tr. 13, at 1806-1807).[145] Although we accept National Grid's explanation and representations in this case, we direct National Grid, in its next base rate case and annual compliance filings to the TIRF mechanism approved in this case, to provide a full and complete explanation of the increases in actual costs compared to estimated costs for

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incomplete projects would be allocated to the last project that is completed for that year (Tr. 13, at 1807-1809).

145 To demonstrate the timing differences associated with National Grid's accounting processes that could result in an uneven allocation of capitalized labor overheads and burdens to individual capital projects, National Grid performed an analysis tracing over time how overheads and burdens were allocated to a total of 21 projects (RR-DPU-95, Att.). Of those 21 projects, the total burdens charged to six projects (project nos. 437849, 337114, 195457, 190315, 479964, 529097) were in line with expectations; seven projects (project nos. 623788, 584504, 445517, 409216, 341826, 295923, 074809) were impacted by the quarterly process undertaken to true-up burden charges; seven projects (project nos. 380797, 379571, 369505, 364290, 349898, 340971, 334593) were impacted by a true-up of the burden charges which took place between October to December 2004, and one project (project no. 312361) was impacted by the true-up of burdens between October to December 2004 and the CWIP clean-up project in 2009 (RR-DPU-95, Att. at 2).

overhead and burden costs, in addition to the required explanation for changes in direct costs in the variance analyses required for projects with costs overruns.[146]

ii. Modifications to SMAs and Closing Reports

A review of the record indicates that a number of the SMAs provided by National Grid are stamped with the phrase "Recreated from Historical Data" (see Exhs. DPU-12-8, Atts. 2 through 10.4; AG-1-19). In addition, the approval sections of these SMAs do not contain the requisite signature indicating approval of the work described therein.[147] National Grid explains that the originally circulated SMAs could not be located but it was possible to recreate the missing original from the data maintained in National Grid's Maximo Work Management system ("Maximo") (Exh. DPU-12-6).[148]

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146 The SMAs and closing reports included in the record indicate the estimated project direct and indirect costs, cost summary by resource category, cost summary by accounting work order and operation, cost unit estimates of material costs including the quantity and item description, and the actual costs broken down by type of expenses further broken down into direct and indirect or burdened costs (see Exhs. DPU-12-8, Atts. 2 through 10.4; AG-1-19).

147 For example, project numbers 111857, 222183, 430162, 370203, 380604, 493257, 523354, 563646, 616241, 633865, 193222, 431790, 492830, 678769, 2497238 on bates stamp pages 1, 1163, 1481, 2639, 2803, 4189, 4460, 5191, 6114, 6364, 7374, 8221, 8405, 9046 of AG-1-19, Books 1 through 14, respectively, and exhibit DPU-12-8-10.1, at 1, show that the SMAs are stamped "Recreated from Historical Data" and contain no signatures in the approval section.

148 Maximo is National Grid's work management system for capital and O&M work performed on the mains, services and other distribution system components encompassed in the Massachusetts service area (Tr. 13, at 1767-1768, 1782; RR-DPU-78). A proposed main work is entered into the system, the scope is determined, the project cost is estimated, and once the necessary approvals for the project are verified, the work order for that project is moved to "approved" status by

Still other SMAs do not contain the notation "Recreated from Historical Data" and, thus, appear to be copies of the original documents. However, these documents have no approval signatures on them.[149] National Grid explains that even though there may be an SMA form without an actual signature on it, the work orders are not entered into the work-order system until it has been verified that the SMA was signed (Tr. 13, at 1771-1772). National Grid states that typically, even with electronic approval, a signatory would email back the signed form (Tr. 13, at 1771-1772; RR-DPU-76). Further, National Grid provides that the unsigned SMAs provided in this case at some point, and in some form, contained a signature because the work orders would not have been put into "approved status" in Maximo and executed forward absent verification of a signature (Tr. 13, at 1771-1772; RR-DPU-76).

We will accept National Grid's explanation and representation in this case. However, we direct National Grid, in its next base rate case and annual TIRF compliance filings, to provide the SMAs with signature(s) showing that each project work order as contained in the

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the Companies' support services organization and applications for the necessary permits and orders for special materials are made (RR-DPU-78).

149 For example, project numbers 344389, 373479, 248793, 312600, 387273, 450553, 497061, 542542, 585431, 636381, 681333, 143507, 524872, 589992 on bates stamp pages 232, 1389, 1817, 2195, 2859, 3520, 4220, 4909, 5607, 6461, 7119, 7824, 8477, and 8758 of Attachment AG-1-19, Books 1 through 14, respectively, show that the SMAs are not stamped "Recreated from Historical Data" but no signatures appear on the approval section of those indicated SMAs.

SMA is approved. The Department requires the same of National Grid's more recent practice of using delegations of authority ("DOAs") in place of SMAs.[150]

Further, we direct National Grid to continue to distinguish between growth-related and non-growth-related projects in the SMAs or DOAs.[151] In addition, we direct National Grid to modify its existing SMA and DOA forms to clearly indicate that whether a capital project is TIRF-related or non-TIRF related. National Grid shall provide as part of its compliance filing to this Order an updated SMA and DOA form, with detailed explanation similar to that provided in exhibits DPU-12-1 and DPU-12-2 that would, among other things, enable the Department to easily identify that a given project covered by an SMA or DOA is a TIRF or non-TIRF project. These revised forms, once approved by the Department in the compliance stage of this proceeding, shall be used by the Companies for all capital projects effective January 1, 2011.

In addition, as of the date of this Order, National Grid is directed to modify its project closing to include: (1) the type of project (i.e., growth-related vs. non-growth-related; TIRF vs. non-TIRF); (2) the date of project initiation; (3) the date that a project was closed; and (4) the date when the plant was placed in service (see Tr. 18, at 2581-2584; RR-DPU-106). In

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150 National Grid notes that a change from the use of SMAs to DOAs began toward the end of 2009 (Tr. 13, at 1770). National Grid adds that, although the DOA form looks different from the SMA, it contains all the same basic information as the shown in the SMA (Tr. 20, at 1770).

151 For non-growth related projects, the SMA indicates "261ESAM" and for growth-related projects, the SMA indicates "261MSAM", with the "E" after numeral "261" representing the code for non-growth-related and the "M" after numeral "261" representing the code for growth-related project (Exh. DPU-12-2, at 1, 7; Tr. 20, at 1778-1779).

this regard, the Department approves National Grid's proposed modifications, as illustrated in its response to record request RR-DPU-106, Attachment.

iii. Conclusion

Despite the above-noted limitations in their capital project documentation, we find that the Companies provided detailed and reviewable project documentation for: (1) Boston Gas' capital projects costing $100,000 or greater from January 1, 2003, through December 31, 2009; (2) Essex Gas' projects costing $50,000 or greater from January 1, 2001, through December 31, 2009; and (3) Colonial Gas' projects costing $50,000 or greater from January 1, 2001, through December 31, 2009. No party raised any issue relating to the prudence or used and usefulness of the above-noted capital projects. Based on our review of those projects, the Department finds them prudent and used and useful.

d. Colonial Gas and Essex Gas Plant Additions Prior to 2001

i. Introduction

Issues related to the capital projects of: (1) Colonial Gas from January 1, 1993 (the year following the test year in Colonial Gas' last rate case, D.P.U. 93-78) through December 31, 2000; and (2) Essex Gas from January 1, 1996 (the year following the test year in Essex Gas' last rate case, D.P.U. 96-70) through December 31, 2000 are addressed below.

As noted above, after the close of evidentiary hearings, the Companies provided support for plant additions made by Essex Gas over the period from January 1, 1999, to December 31, 2000, and Colonial Gas over the period from January 1, 1993 through December 31, 1998, including work orders and closing reports of at least $50,000 (Exh.

AG-1-19, Atts.; RR-DPU-74). National Grid did not produce any documents to support plant additions made by Essex Gas for the period January 1, 1996 through December 31, 1998 (National Grid Brief at IX.8).

The Attorney General argues, both in the case of the late-provided documents for Colonial Gas and Essex Gas and the missing documents for Essex Gas, that National Grid has not provided sufficient evidence to support these major capital additions and, therefore, the investments should not be included in rate base (Attorney General Brief at 99). Conversely, National Grid argues that it has provided sufficient information to support the inclusion of its pre-2001 proposed capital additions in rate base for Colonial Gas and Essex Gas (National Grid Reply Brief at 93). Among other arguments, National Grid contends that the Attorney General ignores the fact that there is no evidence that any imprudence occurred in relation to the projects completed by National Grid since 2001 (National Grid Reply Brief at 93). Further, National Grid claims that, consistent with the Department's ratemaking practice which specifies that the threshold for submission of detailed project documentation is $100,000 for larger companies and $50,000 for smaller companies, it has provided sufficient documentation to support the inclusion of these capital additions in rate base (National Grid Brief at IX.5-6).

We will address the particular capital projects below. However, first, we must clarify issues raised by National Grid in its comment regarding the burden of proof and the purported threshold standard for documentary proof with respect to capital additions. First, National Grid suggests that the absence of evidence of imprudence in other projects warrants a finding of prudence with respect to the projects at issue. Implicit in National Grid's argument is that intervenors bear the burden of proof to demonstrate imprudence. This argument is incorrect.

The burden of proof is the duty imposed upon a proponent of a fact whose case requires proof of that fact to persuade the factfinder that the fact exists or, where a demonstration of non-existence is required, to persuade the factfinder of the non-existence of that fact. D.T.E. 03-40, at 52, D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7. It is clear that, because a utility petitioning for a rate increase seeks the benefit of such a rate increase, the petitioning utility bears the burden of proof by presenting a clear and reasonable analysis. Fryer v, Department of Public Utilities, 374 Mass. 685, 690 (1978); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 578-579 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967). As the Attorney General correctly notes, in order to collect costs from ratepayers for capital additions, the Companies have the burden of proof as to the reasonableness and prudence of capital additions. Prudence must be shown by a preponderance of the evidence. Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967); D.T.E. 03-40, at 52; D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7 & n.5). This is the standard that we must apply here.

Turning to the Companies' interpretation of the Department's standard for documentary proof with respect to capital additions, National Grid is correct that the Department has recognized the value of dollar thresholds as striking a reasonable balance between the need for effective regulatory review of a company's capital projects and the need to avoid devoting considerable resources to the examination of variances in relatively low-cost projects. D.P.U. 08-35, at 22 n.14; D.T.E. 05-27, at 76. However, any inference that the Department has adopted a threshold of $100,000 for larger companies and $50,000 for smaller companies below which inquiry is prohibited is misplaced. Project thresholds relied upon in the discovery process, such as those relied upon in exhibit AG-1-19, do not mean that projects of lower value are exempt from scrutiny or the requirement that a company maintain adequate documentation to support the prudence of these capital additions. Rather, the Department and intervenors may inquire into any project regardless of its final cost.

ii. 1993 through 1998 Colonial Gas Plant Additions and 1999 through 2000 Essex Gas Plant Additions

As part of discovery in this proceeding, the Attorney General requested that National Grid provide copies of: (1) Colonial Gas' capital authorization and closing reports for all projects begun or finished since January 1, 1998, of $50,000 or more; and (3) Essex Gas' capital authorization and closing reports for all projects begun or finished since January 1, 1996, of $50,000 or more (Exhs. AG-1-19; AG-2-19; AG-3-19). In its response, National Grid provided capital authorization and closing reports for projects greater than $50,000 that were begun or completed between January 1, 2001 and December 31, 2009 for both Colonial Gas and Essex Gas (Exhs. AG-1-19; AG-2-19; AG 3-19). However, National Grid explained that because of various company consolidations and changes in recordkeeping systems that had occurred over time, the requested documentation for Colonial Gas and Essex Gas prior to 2001 was no longer available (Exhs. AG-1-19; AG-2-19, AG-3-19; Tr. 13, at 1751-1755).

During the evidentiary hearings, the Department requested that National Grid again review its records for any further documentation of pre-2001 capital additions related to Colonial Gas and Essex Gas (Tr. 13, at 1755, 1761).[152] In response, National Grid provided the work order authorizations and closing reports for ten growth-related and 17 non-growth Colonial Gas projects exceeding $50,000 for the years 1999 through 2000 (RR-DPU-74, Att. A at 1-52, 54-137). National Grid also provided work orders and closing reports for Colonial Gas projects that exceeded $50,000 from 1993 through 1998 (RR-DPU-74, at 2, Att. B). In the case of Essex Gas, National Grid provided documentation for five growth-related projects and 23 non-growth projects exceeding $50,000 in 1999 and 2000 (RR-DPU-74, at 1; Att. A at 148-163, 165-280).

We share the Attorney General's concerns that, late in the proceeding, shortly before intervenors initial briefs were due, National Grid produced additional documents upon request of the Department that it had earlier stated were not available. As we have repeated frequently throughout this Order and, as it bears repeating again here, National Grid has the burden of proof with respect to each element of its case, including the reasonableness and prudence of capital additions. Without clear and cohesive reviewable evidence for capital additions, such investments are subject to disallowance. See D.T.E. 05-27-A at 40-51; D.T.E. 03-40, at 48,

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152 The Attorney General objected to this record request on the grounds that she had previously sought this information from National Grid and also that any information produced would be untimely given the procedural schedule in this case (Tr. 13, at 1758-1759). The hearing officer overruled the objection (Tr. 13, at 1759). The Attorney General did not appeal the hearing officer's ruling to the full Commission.

52; Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993).

The Department takes a dim view of the late production of documents. The time for National Grid to have assembled its documentation to support plant additions was before this case was filed. Further, had National Grid accorded the Attorney General's information request the degree of energy and seriousness that appears to have given the Department's record request seeking the same materials, unnecessary controversy would have been avoided. In future cases, non-responsiveness to issues such as discovery requests will be considered in determining a company's allowed ROE.

Despite National Grid's tardy response, we find that the Companies have provided sufficient information to allow for Department review. As responses to a record request, these documents became part of the evidentiary record in this proceeding and the Attorney General did not seek to have them excluded. Accordingly, in this instance, the Department will rely on this evidence to reach its determination regarding the prudence of plant additions in this case. We have reviewed the documents presented and address the various plant additions below.

Concerning Colonial Gas' 1993 through 1998 plant additions, National Grid provided work order authorizations and closing reports for projects exceeding $50,000 that were provided as evidence during the Department's investigation in D.P.U. 98-128 (RR-DPU-74, Att. B). However, because our investigation in D.P.U. 98-128 was focused on setting Colonial Gas' cast-off revenue requirement as part of its merger cost recovery proposal, versus a traditional rate case pursuant to G.L. c. 164, § 94, the Companies must demonstrate the prudence of these projects as part of this proceeding.

We find that National Grid provided sufficient and reviewable evidence relating to Colonial Gas' capital projects and expenditures for the period from 1993 through 1998. Based on this review, we find that Colonial Gas acted prudently with respect to those projects placed into service from January 1, 1993, through December 31, 1998. Accordingly, we will allow the cost of these projects to be included in Colonial Gas' rate base.

For the period 1999 through 2000, the Department has reviewed the record including the work order authorizations and/or SMAs and closing reports for ten growth-related and 17 non-growth projects exceeding $50,000 (RR-DPU-74, Att. A at 1-137).[153] We find that National Grid provided sufficient and reviewable evidence relating to Colonial Gas' capital projects and expenditures for the period from 1999 through 2000. Based on this review, we find that Colonial Gas acted prudently with respect to those projects placed into service from January 1, 1999, through December 31, 2000. Accordingly, we will allow the cost of these projects to be included in Colonial Gas' rate base.

In the case of Essex Gas, National Grid has identified and provided documentation for five growth-related projects in 1999 and 2000, ranging in actual costs from $53,344 (project no. 15646) to $109,035 (project no. 72154) (RR-DPU-74, at 1; Att. A at 139-163). National

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153 In addition, National Grid provided the annual capital additions and retirements for Colonial Gas from 1993 through 2009 (Exhs. AG-1-2(8), Vol. 12 at 7096-7097; Vol. 13, at 7298-7705; Vol. 14, at 7901-8277; RR-DPU-75, at 2, Att. (B) at 1-20). These annual capital additions and retirements are based on Colonial Gas' annual reports to the Department (Exh. AG-1-2, at 3, AG-1-2, Att. (8); RR-DPU-75, at 2).

Grid also provided documentation for 23 non-growth-related projects during that same period, ranging in actual costs from $51,005 (project no. 84536) to $254,841 (project no. 70520) (RR-DPU-74, at 1; Att. A at 165-280). We find that National Grid provided sufficient and reviewable evidence relating to Essex Gas' capital projects and expenditures for the period from 1999 through 2000. Based on this review, we find that Essex Gas acted prudently with respect to those projects placed into service from January 1, 1999, through December 31, 2000. Accordingly, we will allow the cost of these projects to be included in Colonial Gas' rate base.

iii. 1996 through 1998 Essex Gas Plant Additions

Regarding Essex Gas' plant additions for the years 1996 through 1998, National Grid's only substantiation of these items is found in Essex Gas' annual returns to the Department for those years. The annual returns provide an account-by-account listing of plant additions, retirements, adjustments, and transfers, along with a brief narrative summarizing that year's construction activities (see, e.g., Exh. AG-1-2, Att. (8) at 7, 15). While this type of information is a valuable means of assessing a company's capital additions, the data contained therein do not –nor are they intended to – provide itemized construction costs by individual project or information comparing original project cost estimates with completed project costs. National Grid was unable to rectify the absence of supporting documentation for these plant additions that may have substantiated their inclusion in rate base. These efforts failed to reveal any contemporaneous and reviewable supporting documentation associated with Essex Gas' 1996 through 1998 plant additions. As discussed above, National Grid acknowledges that it bears the burden of providing reviewable documentation for the investments it seeks to include in rate base (National Grid Brief at IX.8, citing D.P.U. 92-210, at 24 (1993); Massachusetts Electric Company, D.P.U. 95-40, at 6-7 (1995)). The Department cannot allow cost recovery where the documentation provided includes only summary plant account information provided in a company's annual returns. See D.T.E. 05-27-A at 47 n. 20.

Based on the foregoing analysis, the Department finds that National Grid has failed to demonstrate that Essex Gas' 1996 through 1998 plant additions were prudently incurred. Accordingly, the Department will exclude these plant costs from Boston Gas-Essex Gas' rate base, as described below.

The Department has examined the account-by-account plant additions made by Essex Gas for the years 1996 through 1998, as provided in its annual reports to the Department. Over this period, Essex Gas' total plant additions were as follows: (1) $7,719,224 during 1996; (2) $7,237,440 during 1997; and (3) $5,483,708 during 1998 (Exhs. AG-1-2, Att. (8) at 15-16, 73-74; RR-DPU-75(A) at 1-2). Therefore, Essex Gas' total gross distribution plant additions made during this period were $20,440,786. Accordingly, the Department will reduce Boston Gas-Essex Gas' proposed plant in service by $20,440,786.

In recognition of the Department's decision to exclude Essex Gas' distribution plant additions made between 1996 and 1998 from rate base, a corresponding adjustment to Essex Gas' depreciation reserve is appropriate. D.P.U. 08-27, at 16; D.T.E. 03-40, at 71. Essex Gas has been applying a composite depreciation rate of 3.70 percent on depreciable plant throughout this period (Exh. AG-1-2, Att. (8) at 38, 89). Therefore, in order to calculate the accumulated depreciation associated with each year, the Department has multiplied this composite depreciation rate by the respective period between the year the plant was installed and the end of the test year in this proceeding (i.e., 13 years for plant installed in 1996, twelve years for plant installed in 1997, and eleven years for plant installed in 1998). Based on this analysis, the Department finds that the associated depreciation reserve for ratemaking purposes is $9,017,708.[154] Accordingly, the Department will reduce Boston Gas-Essex Gas' proposed depreciation reserve by $9,158,423.

Consistent with the above adjustments, a corresponding adjustment to Essex Gas' deferred income tax reserve is also appropriate. D.T.E. 01-56, at 42. In view of the complexities associated with deferred income tax calculations, the Department will derive a representative level of associated deferred income taxes by first dividing Essex Gas' total test year-end accumulated deferred income tax reserve of $23,875,129, by its total net utility plant as of that date of $95,885,263 (Exh. AG-1-101(B) (Rev. 3) at 44). See D.T.E. 01-56, at 43. This produces a factor of 24.90 percent, which when multiplied by the total net plant being excluded from rate base of $11,282,363, produces a deferred income tax balance of $2,809,273. Accordingly, the Department will reduce Boston Gas-Essex Gas' proposed deferred income tax reserve by $2,809,273.

Finally, in view of the above adjustments, it is necessary to eliminate from Boston Gas-Essex Gas' proposed cost of service depreciation expense associated with the disallowed plant additions. D.P.U. 08-27, at 16; D.T.E. 03-40, at 71. The Department has approved

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154 This calculation is as follows: ($7,719,224 x .0370 x 13 years) + ($7,237,854 x .0370 x 12 years) + ($5,483,708 x .0370 x 11 years) = $9,158,423.

account-specific depreciation accrual rates for National Grid (see Section X.0.3, below). Therefore, in order to calculate the annual depreciation expense associated with this plant, the Department has multiplied the account-by-account plant disallowances for Boston Gas- Essex Gas by the corresponding proposed composite depreciation accrual rates for Essex Gas (Exh. AG-1-101(B) (Rev. 3) at 36). Based on this analysis, the Department finds that the associated depreciation expense for the disallowed plant is $820,748. Accordingly, the Department will reduce Boston Gas-Essex Gas' proposed depreciation expense by $820,748.

iv. Conclusion

In order to facilitate the review of capital additions proposed for inclusion in rate base, companies must retain all necessary records, including work order authorizations and closing reports for each project, at least from the beginning of the calendar year after the test year of a company's last base rate case. In the case where a company is acquired or merged during the intervening period between rate cases, the surviving company shall be responsible for preserving and maintaining such records. Further, we emphasize that because of its TIRF, National Grid must maintain continuing and verifiable records for both TIRF and non-TIRF related projects. Careful record keeping practices can avoid the problems of proof encountered in this proceeding. Otherwise, National Grid risks incapacitating problems of proof and consequent denial of cost recovery.

B. 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 or through short-term borrowing. 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 1) 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 computation.

Cash working capital ("CWC") needs have been determined through either the use of a lead-lag study or a 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has generally relied on the 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 1) at 35 (1988). The Department, however, has expressed concern that the 45-day convention first developed in the early part of the 20th century no longer provides a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998). Therefore, the Department requires each gas and electric distribution company to either: (1) conduct a lead-lag study where cost-effective; or (2) propose a reasonable alternative to a lead-lag study to develop a different interval.[155] D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 57 (2002).

2. National Grid's Lead-Lag Studies

a. Summary

National Grid conducted separate lead-lag studies for Boston Gas, Essex Gas, Colonial Gas (Cape Cod) and Colonial Gas (Lowell), and also performed a combined lead-lag study for the Boston Gas-Essex Gas entity and the combined Colonial Gas entity (Exhs. NG-PMN-1, Atts. NG-PMN-LL-2; NG-PMN-LL-2A; NG-PMN-LL-2B; NG-PMN-LL-3; NG-PMN-LL-3A; NG-PMN-LL-3B; DPU-16-8, Atts. NG-PMN-LL-2 (Rev.); NG-PMN-LL-2A (Rev.); NG-PMN-LL-2B (Rev.); NG-PMN-LL-3 (Rev.); NG-PMN-LL-3A (Rev.); NG-PMN-LL-3B (Rev.)).[156] These studies were performed to determine the funding required for the Companies to operate on a day-to-day basis (Exh. NG-PMN-1, at 3). National Grid explains that its lead-lag studies compare (1) the timing difference between the receipt of service by customers and their subsequent payment for these services, and (2) the timing difference between the incurrence of costs by the Companies and their subsequent payment of these costs (Exh. NG-PMN-1, at 3). Thus, the lead-lag studies compute a revenue lag (or lead) and an expense lead (or lag) (Exh. NG-PMN-1, at 3).

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155 In this context, "cost-effective" means that the normalized cost of the study (i.e., the cost of the study divided by the normalization period used in the utility's rate case) is less than the reduction in revenue requirements that would occur using the results of the lead-lag study in lieu of the 45-day convention. D.T.E. 02-24/25, at 57 n.34.

156 National Grid excluded gas costs from the revenue requirement amounts used to calculate CWC in the lead-lag studies (Exh. DPU-5-5).

b. Revenue Lag Factors

According to National Grid, the revenue lag is computed based on the time between the date when customers receive service and the date when they pay for service (Exh. NG-PMN-1, at 4). A revenue lag consists of four components: a "service lag," a "billing lag," a "collection lag," and a "revenue float" (Exh. NG-PMN-1, at 6).[157] The Companies' service lag was obtained by calculating one-half of an average month, which amounts to 15.21 days (Exhs. NG-PMN-1, at 7; NG-PMN-1, Atts. NG-PMN-LL-2A at 2; NG-PMN-LL-2B at 2; NG-PMN-LL-3A at 2; NG-PMN-LL-3B at 2). The billing lag is the time required to process and send out bills (Exh. NG-PMN-1, at 7). National Grid uses an automated meter reading system to read customer meters (Exh. NG-PMN-1, at 7). National Grid reports the billing lag as approximately 1.44 days considering the delay of weekends and holidays (Exhs. NG-PMN-1 at 7; NG-PMN-1, Atts. NG-PMN-LL-2A at 2; NG-PMN-LL-2B at 2; NG-PMN-LL-3A at 2; NG-PMN-LL-3B at 2).

The collection lag represents the time delay between the mailing of customers' bills and the Companies' receipt of the billed revenues (Exh. NG-PMN-1, at 8). The collection lag was calculated using the account receivable turnover method[158] and resulted in a collection lag of 48.95 days for Boston Gas, 37.02 days for Essex Gas, 42.54 days for Colonial Gas (Lowell),

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157 The four revenue lag components are computed in days that correspond to time components: (1) from receipt of service to meter reading; (2) from meter reading to billings; (3) from billing to collection; and (4) the delay in receipt of cash from customers (Exh. NG-PMN-1, at 7-8).

158 The accounts receivable turnover method takes the average daily revenues for the twelve months that ended December 31, 2009 (Exh. NG-PMN-1, at 8).

and 35.81 days for Colonial Gas (Cape Cod) (Exhs. NG-PMN-1, at 8; NG-PMN-1, Atts. NG-PMN-LL-2A at 2; NG-PMN-LL-2B at 2; NG-PMN-LL-3A at 2; NG-PMN-LL-3B at 2).

Finally, National Grid defines the revenue float as the time difference between when funds are received from customers until customer payments clear the banks and are available to the Companies (Exh. NG-PMN-1, at 8). National Grid states that there are two periods of float (Exh. NG-PMN-1, at 8). The first is associated with the Companies' payment of services from vendors, and is referred to as expense float (Exh. NG-PMN-1, at 8). The second period of float is the delay in receipt of cash from customer payments (Exh. NG-PMN-1, at 8). In this instance, the Companies' cash requirements are reduced by the delay in mailing and check processing (Exh. NG-PMN-1, at 8). Given the potential complexity inherent in the float calculations, National Grid decided not to include these calculations in its CWC analysis (Exh. NG-PMN-1, at 8-9).

Based on the lead-lag studies, National Grid concludes that the revenue lag for Boston Gas is 65.58 days, the revenue lag for Essex Gas is 53.65 days, the revenue lag for Colonial Gas (Lowell) is 59.17 days, and the revenue lag for Colonial Gas (Cape Cod) is 52.44 days (Exhs. NG-PMN-1 at 4; NG-PMN-1, Atts. NG-PMN-LL-2A at 1, 2; NG-PMN-LL-2B at 1, 2; NG-PMN-LL-3A at 1, 2; NG-PMN-LL-3B at 1, 2).

c. Expense Lag Factors

The expense lag is calculated as the number of days between the date when the Companies receive goods or services from a vendor and the date when the Companies pay for such goods or services (Exh. NG-PMN-1, at 4). If the expenses are paid before the services are provided, then the expense lag is expressed as a negative amount (Exh. NG-PMN-1, at 4-5). Consequently, any increase in the number of expense lag days results in a reduction of the amount of working capital required for ongoing National Grid operations (Exh. NG-PMN-1, at 5).

The expense lag comprises several different categories of O&M expenses, including direct labor, allocated labor, health benefits and 401K contributions, outside service and regulatory commission expenses, uncollectible accounts, pension expenses, and expenses allocated from National Grid's various service companies (Exhs. NG-PMN-1, at 9-11; NG-PMN-1, Atts. NG-PMN-LL-2A at 1, 3; NG-PMN-LL-2B at 1, 3; NG-PMN-LL-3A at 1, 3; NG-PMN-LL-3B at 1, 3). The expense lag also includes property taxes, payroll taxes, and unemployment taxes (Exhs. NG-PMN-1, at 12; NG-PMN-1, Atts. NG-PMN-LL-2A at 1, 3; NG-PMN-LL-2B at 1, 3; NG-PMN-LL-3A at 1, 3; NG-PMN-LL-3B at 1, 3).

Based on the lead-lag studies, National Grid concludes that the expense lag for Boston Gas is 33.46 days, the expense lag for Essex Gas is 19.17 days, the expense lag for Colonial Gas (Lowell) is 31.26 days, and the expense lag for Colonial Gas (Cape Cod) is 40.26 days (Exhs. NG-PMN-LL-2A at 1; NG-PMN-1, Atts. NG-PMN-LL-2B at 1; NG-PMN-LL-3A at 1; NG-PMN-LL-3B at 1).

d. Net Lag Factors

The arithmetic difference between the computed revenue lag and the computed expense lag is the number of days that stockholders must provide funding for the Companies' daily operations (Exh. NG-PMN-1, at 5). National Grid calculates the net lag days for Boston Gas as 32.13 days, the net lag days for Essex Gas as 34.48 days, the net lag days for Colonial Gas (Lowell) as 27.91 days, and the net lag days for Colonial Gas (Cape Cod) as 12.18 (Exhs. NG-PMN-1, at 5, 12-13; NG-PMN-1, Atts. NG-PMN-LL-2A at 1; NG-PMN-LL-2B at 1; NG-PMN-LL-3A at 1; NG-PMN-LL-3B at 1).

Cash working capital factors were derived by dividing the net lag days by 365 days (Exhs. NG-PMN-1, Atts. NG-PMN-LL-2A at 1, NG-PMN-LL-2B at 1, NG-PMN-LL-3A at 1, NG-PMN-LL-3B at 1). Those factors then were multiplied by the respective Companies' pro forma O&M expenses to arrive at the CWC requirements (Exhs. NG-PMN-1, Atts. NG-LL-2A at 1; NG-LL-2B at 1; NG-LL-3A at 1; NG-LL-3B at 1; DPU-16-8, Atts. NG-LL-2A (Rev.) at 1; NG-LL-2B (Rev.) at 1; NG-LL-3A (Rev.) at 1; NG-LL-3B (Rev.) at 1). On a pro forma basis, National Grid calculates its required CWC requirements as $21,056,685 for Boston Gas, as $888,513 for Essex Gas, as $2,069,602 for Colonial Gas (Lowell), and as $652,419 for Colonial Gas (Cape Cod) (Exhs. NG-PMN-1, at 13; NG-PMN-1, Atts. NG-PMN-LL-2A at 1; NG-PMN-LL-2B at 1; NG-PMN-LL-3A at 1; NG-PMN-LL-3B at 1).

e. Combined Lead-Lag Results

National Grid also calculated the net lag and CWC requirements for Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-PMN-1, at 6, 13; NG-PMN-1, Atts. NG-PMN-LL-2, at 1; NG-PMN-LL-3, at 1). The combined net lag and CWC requirements for Boston Gas-Essex Gas are 32.22 days and $21,945,198 (Exhs. NG-PMN-1, at 13; NG-PMN-1, Att; NG-PMN-LL-2, at 1). The combined net lag and CWC requirements for Colonial Gas are 21.31 days and $2,722,021 (Exhs. NG-PMN-1, at 13; NG-PMN-1, Att. NG-PMN-LL-3, at 1). No party challenged National Grid's lead-lag studies or otherwise commented on the results.

3. Analysis and Findings

In its initial filing, National Grid reports that the net lags associated with the lead-lag studies were 32.23 days for Boston Gas-Essex Gas, and 21.31 days for Colonial Gas (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 46; NG-MDL-2 Colonial Gas (Rev. 3) at 45). These lags produce lower results than the Department's 45-day convention (Exhs. NG-PMN-1, Atts. NG-LL-2; NG-LL-2A; NG-LL-2B; NG-LL-3; NG-LL-3A; NG-LL-3B; RR-DPU-91, Att.). Moreover, National Grid calculated costs associated with preparing these studies at $90,009 (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 32; NG-MDL-2 Colonial Gas (Rev. 3) at 31; RR-DPU-46(A) (Supp. 3) at 1, 2). In view of the resulting reduction in CWC needs versus the cost of the lead-lag studies, the Department finds that the Companies' decision to perform lead-lag studies was cost-effective. In its original filing, National Grid proposed to apply the results of this study to meet its cash working capital needs, through a composite CWC requirement of 32.22 days and $21,945,198 for Boston Gas-Essex Gas, and a CWC requirement of 21.31 days and $2,722,021 for Colonial Gas (Exhs. NG-PMN-1, at 13; NG-PMN-1, Atts. NG-PMN-LL-2, at 1; NG-PMN-LL-3, at 1).

During the proceedings, National Grid identified an error in the calculation of a number of charges, most of which pertained to service company charges (Exh. DPU-5-12). According to the Companies, a review of the lag days calculation for Outside Services Account 923 indicated that certain payment dates were inadvertently not updated on the Companies' workpapers (Exh. DPU-5-12). After correcting for these errors, National Grid calculated a CWC requirement of 32.63 days and $22,227,939 for Boston Gas-Essex Gas, and 21.79 days and $2,783,110 for Colonial Gas (Exhs. DPU-5-12; DPU-16-8, Atts. NG-PMN-LL-2 (Rev.); NG-PMN-LL-3 (Rev.); Tr. 9, at 1233-1234). The Department has reviewed the Companies' calculations and accepts the proposed revisions to the calculation of the Outside Service Account 923 lag days. The effect of this correction on the CWC allowances is detailed on Schedule 6 of this Order.

Next, National Grid calculates a test year collection lag of 48.95 days for Boston Gas, which is significantly higher than the collection lags for Essex Gas, Colonial Gas (Cape Cod), and Colonial Gas (Lowell) (Exhs. NG-PMN-1, Atts. NG-PMN-LL-2A at 2; NG-PMN-LL-2B at 2; NG-PMN-LL-3A at 2; NG-PMN-LL-3B at 2; DPU-16-2).[159] Further, the collection lag of 48.95 days for Boston Gas is higher than experienced by Boston Gas in 2007 (42.18 days) and 2008 (43.93 days) (RR-DPU-55, Atts. A, B). National Grid states that the differences in collection lags are based on differences in customer composition and their respective payment patterns (Exh. DPU-16-2). Further, National Grid submits that a collection lag is a function of the economy, population demographics, and the types of customers buying gas (Tr. 9, at 1264; Tr. 10, at 1405). In addition, National Grid contends that it is difficult to isolate any particular segment that would lead to the increased collection lag, and that it has not examined the reason for the increase in the collection lag over the past two to three years (Tr. 9, at at 1265-1266).

[159] This collection lag calculation did not change when National Grid revised the calculation of the Outside Service Account 923 lag day (see Exh. DPU-16-8, Att. NG-PMN-LL-2A (Rev.) at 2).

The Department finds that Boston Gas experienced an unusually high collection lag in the test year.[160] A collection lag of this magnitude, however, was not evident in 2007 or 2008 (see RR-DPU-55, Atts. A, B), nor has it persisted beyond the test year.[161] As such, the test year collection lag for Boston Gas is an anomaly and not representative of both past and present time delay between the issuance of customers' bills and the receipt of billed revenues. The Department, therefore, finds that it is reasonable and appropriate to adjust the test year collection lag to reflect a more representative delay period. The collection lag ultimately will affect the total CWC approved for Boston Gas and, as such, it is essential that Boston Gas collect an amount of CWC that meets, and not exceeds, its actual needs.

The average of Boston Gas' 2007 and 2008 collection lags amounts to 43.06 days (RR-DPU-55, Atts. A, B). This collection lag amount more closely resembles Boston Gas' past collection lags, and is consistent with the collection lags that have been reported to the Department in National Grid's recent filings (Exh. DPU-16-1, Att. A at 2; Boston Gas Company, Colonial Gas Company, and Essex Gas Company, each d/b/a as National Grid,

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160 We recognize that the financial crisis experienced in the United States during the test year certainly could be a factor in the unusually large collection lag, as customers may have delayed bill payments longer than normal during this period. National Grid, however, does not provide any empirical evidence to support the reason(s) for the higher collection lag.

161 For instance, Boston Gas' collection lag applicable for firm customers, as reported in its March 15, 2010, off-peak gas cost reconciliation filing, is 42.86 days (Exh. DPU 16-1, Att. A at 2). In addition, National Grid calculated a 43.54 day lag for Boston Gas' firm customers in its most recent Cost of Gas Adjustment filing. See Boston Gas Company, Colonial Gas Company, and Essex Gas Company, each d/b/a as National Grid, D.P.U. 10-GAF-P5 Company Filing, Revised Peak Local Distribution Adjustment Factor Att. B at 13 (September 17, 2010).

D.P.U. 10-GAF-P5 Company Filing, Revised Peak Local Distribution Adjustment Factor Att. B at 13 (September 17, 2010)). Based on these considerations, the Department finds that the average of the 2007 and 2008 collection lags is a fair representative test year collection lag for Boston Gas, and will serve as the basis for future collection lag costs.

Based on the above adjustments, the Department calculates a CWC requirement of 27.21 days for Boston Gas-Essex Gas and a CWC requirement of 21.79 days for Colonial Gas (Exhs. DPU-16-8, Atts. NG-LL-2 (Rev.) at 1; NG-LL-3 (Rev.) at 1). Application of these lead-lag factors to the levels of O&M expense authorized by this Order produces a cash working capital allowance of $18,545,454 for Boston Gas-Essex Gas and $2,790,317 for Colonial Gas. The derivation of these cash working capital allowances are provided on Schedule 6 (Boston Gas-Essex Gas) and Schedule 6 (Colonial Gas) of this Order.

C. Accumulated Deferred Income Taxes

1. Introduction

As of the end of the test year, Boston Gas-Essex Gas and Colonial Gas had on their books a total accumulated deferred federal and state income tax balance of $255,307,044 and $90,698,563, respectively (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 43; NG-MDL-2-Colonial Gas (Rev. 3) at 42). Deferred income taxes arise because of differences between the tax and book treatment of certain transactions, including the use of accelerated depreciation and the treatment of certain operating expenses for income tax purposes. Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). According to National Grid, a 2009 ruling by the Internal

Revenue Service ("IRS") concerning certain types of repair work that had been capitalized by the Companies resulted in a one-time tax benefit of $74 million for Boston Gas-Essex Gas, as well as a one-time tax benefit of $12 million for Colonial Gas (Exh. NG-MDL-1, at 46, 81). While the Companies included this tax benefit in their deferred tax balance, National Grid notes that this tax position remains subject to IRS audit and adjustment (Exh. NG-MDL-1, at 46-47, 81). Therefore, National Grid requests that any positive or negative adjustments be accounted for through the TIRF calculation in order to ensure that customers receive the full benefit of the tax position, and to ensure that the Companies' rate base is computed consistently with the tax position allowed by the IRS (Exh. NG-MDL-1, at 47, 81-82).

Boston Gas-Essex Gas deducted from its deferred income tax balance $17,986,133 in deferred income taxes associated with contributions in aid of construction ("CIAC"), while Colonial Gas deducted $3,092,504 in CIAC-related deferred income taxes (Exhs. AG-26-4; AG-26-7; Tr. 8, at 1112-1113). Because CIAC represent taxable income to a utility, the Companies have been charging the tax gross-up associated with a CIAC to the individual customer for whom the investment is being made (see RR-DPU-85).[162]

2. Positions of the Parties

a. Attorney General

According to the Attorney General, deferred income taxes provide a cost-free source of funds to a utility, and are thus treated as a deduction to rate base (Attorney General Brief

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[162] CIAC has been considered taxable income since the passage of the Tax Reform Act of 1986. New England Gas Company, D.P.U. 08-35, at 46 n.31 (2008); see also Massachusetts-American Water Company, D.P.U. 95-118, at 81 (1996).

at 104). However, the Attorney General notes that Boston Gas-Essex Gas' deferred income tax balance was reduced by $17,986,000, and Colonial Gas' deferred income taxes were reduced by $3,092,000, for deferred income taxes associated with CIAC (Attorney General Brief at 105, citing Exhs. AG 26-4, AG 26-7; Tr. 8, at 1110-1113). The Attorney General contends that the Department has previously found that reductions to deferred income tax balances arising from CIAC would deny customers the full benefit of these deferred income taxes (Attorney General Brief at 105, citing Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 119 (2009)).

The Attorney General maintains that the Companies have failed to substantiate their proposed treatment of CIAC-related deferred income taxes (Attorney General Reply Brief at 45). The Attorney General disputes National Grid's claim that the Department approved the removal of deferred income taxes associated with CIAC in D.P.U. 03-40, and argues that there is no evidence that the Department even considered that issue in D.P.U. 03-40 (Attorney General Reply Brief at 45). The Attorney General contends that any sub silentio acceptance by the Department of an issue does not preclude a different treatment upon a finding that it is warranted (Attorney General Reply Brief at 45, citing Western Massachusetts Electric Company, D.T.E./D.P.U. 06-35-A/06-105-B/07-11-A at 22 (2008); Western Massachusetts Electric Company, D.P.U. 03-34, at 6 (2004), Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 24 (2001); Boston Gas Company, D.P.U. 96-50-C (Phase I) at 33 (1997); NYNEX Price Cap, D.P.U. 94-50, at 444 (1995); Robinson v. Department of Public Utilities, 416 Mass. 668, 673 (1993)).

Therefore, the Attorney General proposes that the deferred tax balances related to CIAC should be added back to National Grid's deferred income tax balances (Attorney General Brief at 105; Attorney General Reply Brief at 46). The effect of her proposed adjustment would increase Boston Gas-Essex Gas' deferred income tax reserve by $17,986,000, and increase Colonial Gas' deferred income tax reserve by $3,092,000, and reduce their rate bases by corresponding amounts (Attorney General Brief at 105).

b. National Grid

National Grid contends that the Attorney General's argument is based solely on the Department's decision in D.P.U. 09-39 (National Grid Brief at IX.10). The Companies assert that the Department approved their proposed treatment of deferred tax assets related to CIAC in Boston Gas' previous rate decision in D.P.U. 03-40 (National Grid Brief at IX.10). National Grid argues that other than a "passing reference" to D.P.U. 09-39, the Attorney General fails to offer any record evidence of any changes in the Department's treatment of CIAC-related deferred tax assets since D.P.U. 03-40 (National Grid Brief at IX.10-11). In contrast, National Grid provides on reply brief in the form of attachments certain exhibits from Boston Gas' previous rate case in D.T.E. 03-40 purporting to demonstrate that the Department was aware of that company's treatment of CIAC-related deferred income taxes (National Grid Reply Brief at 98-99).

The Companies distinguish the situation here from those the Department encountered in D.P.U. 09-39 and New England Gas Company, D.P.U. 08-35 (2009) (National Grid Reply Brief at 95-96). According to National Grid, the Department concluded in both of those cases that, if the CIAC gross-up for income taxes is credited to plant, it is appropriate to include the deferred tax asset in rate base in order to remove the rate base reduction associated with the tax component of the total CIAC credit (National Grid Reply Brief at 97). However, the Companies maintain that if the CIAC tax gross-up is not included in the CIAC credit to plant, it is appropriate to exclude the associated deferred taxes from rate base (National Grid Reply Brief at 97). The Companies demonstrate this by way of example, assuming a hypothetical CIAC of $100 and a CIAC tax gross-up of $54 (National Grid Reply Brief at 98). National Grid maintains that while its deferred income tax calculation for this CIAC demonstrates that the net effect on rate base resulting from its treatment of CIAC-related deferred income taxes is zero, the Attorney General's method produces a rate base deficit equal to the CIAC tax gross-up of $54 (National Grid Reply Brief at 98).

3. Analysis and Findings

Because deferred income taxes represent a cost free source of funds to the utility, they are typically treated as an offset to rate base. D.P.U. 87-59, at 29; AT&T Communications of New England, Inc., D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983). The Department, however, also has a general policy of matching recovery of tax benefits and losses to the recovery of the underlying expense with which the tax effects are associated. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase I) at 29 (1991); Massachusetts Electric Company, D.P.U. 89-194/195, at 66 (1990).

In this proceeding, Boston Gas-Essex Gas removed from its year-end accumulated deferred income tax balance $17,986,133 in CIAC-related deferred income taxes, and Colonial

Gas removed $3,092,504 in CIAC-related deferred income taxes (Exhs. AG 26-4; AG 26-7). In the case of the CIAC tax gross-up, a utility receives the total tax equivalent of the CIAC from the individual customer receiving the benefit of the CIAC investment, and is therefore not required to finance this current tax payment. Thus, both the deferred income tax amount and the decision on whether it is included in rate base is dependent upon whether the utility recorded the original CIAC tax gross-up as a credit to plant or as other income.

Pursuant to the Uniform System of Accounts for Gas Companies ("USOA-Gas"), CIAC is included in the gas plant accounts, with an offsetting entry to Account 271, Contributions in Aid of Construction. See 220 C.M.R. § 50, Gas Plant Instructions § 2(E). When the CIAC tax gross-up is credited to plant, as in the case of a gas utility, the company receives the cash tax requirement on the total CIAC from the individual customer who is benefitting from the CIAC investment, meaning that the company is not required to finance this tax payment. Consequently, it would be appropriate to include the CIAC-related deferred income taxes in rate base (via a deduction from the deferred income tax balance) in order to remove the rate base deduction associated with the CIAC portion of the total credit to plant. In contrast, the Uniform System of Accounts for Electric Companies, ("USOA-Electric") requires that CIAC be deducted from the electric plant accounts. 220 C.M.R. § 51.01(1) (Adoption of FERC Uniform System of Accounts), USOA-Electric, Electric Plant Instructions.[163] If the CIAC tax gross-up is not credited to plant, as would be the case with an

163 While the Department has adopted the version of the USOA-Electric prescribed by the Federal Energy Regulatory Commission, with several modifications thereto, the

electric utility, the company must then finance this tax payment. Consequently, it would be appropriate to inlude the CIAC-related deferred income taxes in the total accumulated deferred income taxes.

The propriety of National Grid's proposed treatment can be demonstrated through example. Assuming a CIAC of $100, and CIAC-related income taxes equal to 60 percent of that amount, or $60, the total required customer contribution would be $160 (i.e., $100 for CIAC and $60 representing the tax liability associated with CIAC), and the net cash outlay to the company would equal zero. The rate base effects of this transaction would consist of an increase to plant in service of $100 and an increase to accumulated deferred income taxes of $60, with a corresponding offset in the form of CIAC of $160. Thus, the company is made whole by the customer for both the investment made on its behalf and the associated income taxes on the CIAC.

Based on the foregoing analysis, the Department finds that National Grid has properly accounted for CIAC-related accumulated deferred income taxes. Accordingly, the Department declines to accept the Attorney General's proposal.

Finally, National Grid proposes to use the TIRF mechanism to adjust deferred income taxes arising from any future IRS actions concerning the treatment of previously-capitalized repair expenses (Exh. NG-MDL-1, at 47, 81-82). The TIRF mechanism is intended to provide for recovery of a discrete category of capital costs related to the systematic replacement of unprotected steel and small-diameter cast iron mains. The TIRF is not intended to be used as

Department has not adopted FERC's version of the USOA-Gas. D.P.U. 08-35, at 44 n.28.

what may be charitably be described as a "catchbasin" for assorted rate base adjustments arising from situations unrelated to the TIRF. Accordingly, the Department disallows the Companies' request in that regard.

D. Prepayments

1. Introduction

As of the end of the test year, Boston Gas-Essex Gas had $23,737,788 in prepayments, while Colonial Gas had $5,859,725 in prepayments (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 43; NG-MDL-2 Colonial Gas (Rev. 3) at 42). National Grid proposes to remove $23,547,390 and $5,733,334 in prepayments from Boston Gas-Essex Gas and Colonial Gas, respectively, because these represent gas payments that are financed through the Companies' money pool and recovered through the CGAC (Exhs. NG-MDL-1, at 47-48, 82; NG-MDL-2 Boston Gas (Rev. 3) at 44; NG-MDL-2 Colonial Gas (Rev. 3) at 43). Therefore, National Grid proposes to include in rate base the remaining prepayments of $190,398 for Boston Gas and $126,391 for Colonial Gas (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 43; NG-MDL-2 Colonial Gas (Rev. 3) at 42).

2. Analysis and Findings

The Department has previously found that, in the absence of evidence that prepayments provide benefits to ratepayers, they are to be excluded from rate base because they are but one of a myriad of positive and negative offsets that are recognized in a company's cash working capital allowance. Boston Gas Company, D.P.U. 93-60, at 60 (1993); Boston Gas Company, D.P.U. 88-67, Phase I at 62-63 (1988); Western Massachusetts Electric Company, D.P.U. 84-25, at 60-61 (1984). The Department finds no basis to support the inclusion of the Companies' prepayments in rate base. Therefore, the Department will reduce National Grid's proposed rate base by $190,398 for Boston Gas-Essex Gas, and by $126,391 for Colonial Gas.

IX. REVENUES

A. Weather Normalization Adjustment

1. Introduction

National Grid proposes a weather normalization adjustment to normalize the effects on test year revenues from warmer-than-normal or colder-than-normal weather experienced during the test year (Exh. NG-AEL-1, at 4). National Grid conducted a weather normalization analysis on a customer-by-customer basis for all rate classes with the exception of the Boston Gas G-44 and G-54 classes[164] and the Essex Gas G-53 rate class[165] (Exh. NG-AEL-1, at 5). National Grid's billing system allows for the calculation of weather-normalized throughput for each bill issued during every month of the test year for all weather-sensitive classes (Exh. NGAEL-1, at 5). The billing system breaks down each customer's actual use into base load use and heating load use (Exh. NG-AEL-1, at 5).

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164 Customers taking service under the Boston Gas G-44 and G-54 rate tariffs are currently billed on a demand basis, rather than a volumetric basis (Exh. NG-AEL-1, at 7). The demand charge is calculated based on the customer's maximum daily contract quantity ("MDCQ") in a relevant historical period (Exh. NG-AEL-1, at 7). To derive the weather impact on the G-44 and G-54 classes, the aggregate MDCQ for each class was weather normalized (Exhs. NG-AEL-1, at 7-8; NG-AEL-2, at 12-13).

165 There are only four customers served by Essex Gas' G-53 tariff (Exh. NG-AEL-1, at 8). Under that tariff, the MDCQ is not reset each year, so it does not change each year based on the prior year's actual usage (Exh. NG-AEL-1, at 8). As such, National Grid submits that a weather normalized revenue adjustment was not necessary for this rate class (Exh. NG-AEL-1, at 8).

Base load use is calculated annually for customers based on July and August consumption, and actual heating load use is calculated as the difference between billed use and base load use (Exhs. NG-AEL-1, at 5; AG-23-5). National Grid calculated normal heating use by multiplying actual heating use by the ratio of the 20-year annual average of heating degree days to actual heating degree days for the associated billing period for each customer, and then adding normal heating use and base load use to obtain normal volumes (Exh. NG-AEL-1, at 6). National Grid calculated normal degree days by averaging the daily degree days recorded at Logan Airport over the 20-year period from January 1990 through December 2009 (Exh. NG-AEL-1, at 6). National Grid notes that this is the same method used to calculate normal degree days for Boston Gas in its prior two rate filings and in each of the annual PBR filings (Exh. NG-AEL-1, at 6). National Grid calculated the weather normalization adjustment as the difference between the actual and normal base-rate revenue for all weather-sensitive classes (Exh. NG-AEL-1, at 6-7).

National Grid's proposed weather normalization adjustment decreases test year revenues for Boston Gas-Essex Gas by $1,787,096 and decreases test year revenues for Colonial Gas by $509,157 (Exhs. NG-AEL-1, at 5; NG-AEL-2, at 5, 23; NG-MDL-2-Boston Gas (Rev. 3) at 5; NG-MDL-2 Colonial Gas (Rev. 3) at 5). No party commented on the proposed adjustments.

2. Analysis and Findings

The Department's standard for weather normalization of test year revenues is well established. See, e.g., D.T.E. 03-40, at 22; D.T.E. 02-24/25, at 75; D.P.U. 96-50 (Phase I) at 36 39; Boston Gas Company, D.P.U. 93-60, at 75-80 (1993). We find that the method National Grid used to weather normalize test year revenues is consistent with this precedent (See Exhs. NG-AEL-1, at 5-9; NG-AEL-2, at 3-13). Therefore, we approve National Grid's proposed weather normalization adjustments, which reduce test year revenues for Boston Gas-Essex Gas by $1,787,096 and reduce test year revenues for Colonial Gas by $509,157.

B. Billing Day Adjustment

1. Introduction

National Grid proposes a billing day adjustment to account for the revenue impact caused by the difference between the number of billing days in a normal year (365.25) and the number of billing days in the test year (363.9) (Exh. NG-AEL-1, at 9). The proposed billing day adjustment increases test year revenues by $1,568,300 for Boston Gas-Essex Gas and increases test year revenues by $510,407 for Colonial Gas (Exhs. NG-AEL-1, at 10; NG-AEL-2, at 14-15, 30-31; NG-MDL-2-Boston Gas (Rev. 3) at 5; NG-MDL-2-Colonial Gas (Rev. 3) at 5). No party commented on the proposed adjustments.

2. Analysis and Findings

The average number of days in a utility's monthly reading schedule often varies by billing cycle. Consequently, the average number of billing days in a given month will not necessarily equal the number of calendar days for that month. Therefore, the Department adjusts test year revenues to recognize the level of revenues that would likely be collected during a normal calendar year. See, e.g., D.T.E. 03-40, at 10; D.P.U. 96-50 (Phase I) at 39-40; D.P.U. 93-60, at 80-83.

The Department finds that the Companies have calculated the proposed billing day adjustments consistent with Department precedent such that the results accurately represent the revenues that would be collected during a normal calendar year (See Exhs. NG-AEL-1, at 9-10; NG-AEL-2, at 14-15; 30-31). Therefore, the Department approves National Grid's proposed billing day adjustments which increase test year revenues for Boston Gas-Essex Gas by $1,568,300 and increase test year revenues for Colonial Gas by $510,407.

C. PBR Revenue Adjustment

1. Introduction

In Boston Gas Company, D.P.U. 09-86 (2009), the Department approved Boston Gas' sixth annual performance base distribution rate adjustment for effect November 1, 2009. National Grid proposes to annualize the rate change approved in that proceeding for the months of January through October 2009 by increasing Boston Gas' test year revenues by $4,263,037 (Exhs. NG-AEL-1, at 12; NG-AEL-2, at 19; NG-MDL-2-Boston Gas (Rev. 3) at 5). No party commented on the proposed adjustment.

2. Analysis and Findings

The Department finds that National Grid's proposed PBR revenue adjustment is reasonable because it annualizes changes in rates during the test year to reflect a representative revenue level. See, e.g., D.T.E. 02-24/25, at 76. Therefore, the Department approves National Grid's proposed PBR revenue adjustment which increases test year revenues for Boston Gas-Essex Gas by $4,263,037.

D. Unbilled Revenues Adjustment

1. Introduction

National Grid proposes an unbilled sales/revenue adjustment to account for the difference between the amount of gas delivered to customers during the test year and the amount of gas billed to customers during that same period (Exh. NG-AEL-1, at 10-11). National Grid states that, every month, the Companies book an accrual for the actual unbilled revenues that compares the actual sendout and actual billing data to derive actual unbilled revenues and sales (Exh. NG-AEL-1, at 11). National Grid states that because both the Boston Gas-Essex Gas and the Colonial Gas test year sales are based on weather normalized (i.e., not actual test year) billing data, the accrual for the amount of actual unbilled sales and associated revenue must be removed from test year revenue (Exh. NG-AEL-1, at 11). National Grid notes that this method was used by Boston Gas in calculating revenues in each of the compliance filings made pursuant to the first and second term of its PBR plan (Exh. NG-AEL-1, at 11).

National Grid booked revenues from unbilled sales during the test year as follows: (1) $6,318,187 to Boston Gas-Essex Gas; and (2) $1,077,071 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial Gas (Rev. 3) at 4). National Grid proposes to remove these amounts from the Companies' test year revenues (Exhs. NG-AEL-1, at 10-11; NG-AEL-2, at 1, 19; NG-AEL-3, at 1, 7; NG-MDL-2- Boston Gas (Rev. 3) at 4, 5; NG-MDL-2-Colonial Gas (Rev. 3) at 4, 5). No party commented on the proposed adjustments.

2. Analysis and Findings

The Department has found that unbilled revenues should be included in test year cost of service. See D.T.E. 03-40, at 12; D.T.E. 01-56, at 32. National Grid has calculated the proposed unbilled sales/revenues adjustment consistent with the method approved by the Department in D.T.E. 03-40 and the subsequent Boston Gas PBR compliance filings (See Exh. NG-AEL-1, at 11). Therefore, the Department approves National Grid's proposed unbilled sales/revenue adjustments which reduce test year revenues for Boston Gas-Essex Gas by $6,318,187 and reduce test year revenues for Colonial Gas by $1,077,071.

E. Broker Revenues Adjustment

1. Introduction

During the test year, National Grid booked revenues billed to third-party gas suppliers (i.e., brokers) as follows: (1) $3,776,237 to Boston Gas-Essex Gas; and (2) $904,251 to Colonial Gas (NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2 Colonial Gas (Rev. 3) at 4). According to National Grid, third-party gas suppliers are billed when the gas consumed by their transportation customers exceeds the gas the third-party gas suppliers delivered to the Companies' gate stations (Exhs. NG-AEL-1, at 13; AG-23-8). This revenue is flowed back to customers through the Companies' respective CGAC (Exhs. NG-AEL-1, at 13; DPU-2-17; AG-23-8). National Grid proposes to remove these amounts from the Companies' test year revenues (Exhs. NG-AEL-1, at 13; NG-AEL-2, at 1, 19; NG-MDL-2-Boston Gas (Rev. 3) at 4, 5; NG-MDL-2 Colonial Gas (Rev. 3) at 4, 5; DPU-2-17). No party commented on the proposed adjustments.

2. Analysis and Findings

Revenues billed to third-party gas suppliers or brokers during the test year are not directly associated with distribution rates. D.T.E. 03-40, at 17. Accordingly, in order to establish a representative level of annual revenues to establish base rates, Boston Gas and Colonial Gas must remove broker revenues from their total operating revenues. D.T.E. 03-40, at 17. The Department finds that National Grid correctly calculated the proposed adjustment to remove revenues billed to brokers during the test year (See Exhs. NG-AEL-1, at 13; NG-AEL-2, at 1, 19; DPU-2-17; DPU-2-18; AG-23-8; AG-23-9). Therefore, the Department approves National Grid's proposed adjustments which reduce test year revenues for Boston Gas-Essex Gas by $3,776,237 and reduce test year revenues for Colonial Gas by $904,251.

F. Customer Adjustment

1. Introduction

National Grid states that, throughout the course of a year, the Companies may at times reduce customer bills for a variety of reasons (Exh. NG-AEL-1, at 13). These billing adjustments reduce the Companies' test year revenues (Exh. DPU-2-19). National Grid proposes to remove from test year revenues the effect of these miscellaneous manual bill reductions that are made at the Companies' discretion (Exhs. NG-AEL-1, at 13; DPU-2-19). National Grid proposes to increase test year revenues for Boston Gas-Essex Gas by $483,967 and to increase test year revenues for Colonial Gas by $316,015, to correct for these miscellaneous adjustments (Exhs. NG-AEL-1, at 13; NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2 Colonial Gas (Rev. 3) at 4). No party commented on the proposed adjustments.

2. Analysis and Findings

In determining a representative level of test year revenues, the Department finds it appropriate to allow adjustments that eliminate the effects of any manual bill adjustments given to customers. Nantucket Electric Company, D.P.U. 91-106/138, at 12-14 (1991). Removal of these test year customer credits effectively increases test year revenues and, thereby, reduces the overall revenue increase sought by National Grid in this proceeding. Therefore, the Department approves National Grid's proposed customer adjustments which increase test year revenues for Boston Gas-Essex Gas by $483,967 and increase test year revenues for Colonial Gas by $316,015.

G. Administrative Fees and Charges Adjustment

1. Introduction

National Grid proposes to standardize the tariffed administrative fees and charges for Boston Gas, Essex Gas and Colonial Gas (Exh. NG-AEL-1, at 14). National Grid states that its proposed changes to fees and charges are intended to simplify the Companies' tariffs and to recognize that the Companies' Massachusetts gas distribution operations are managed on a fully integrated basis (Exh. DPU-2-21).

National Grid proposes to use the existing Boston Gas schedule of administrative fees and charges as the basis for the proposed fees and charges for Boston Gas-Essex Gas and Colonial Gas (Exh. DPU-2-21). Specifically, National Grid proposes to: (1) standardize the returned check charge at $15.00;[166] (2) eliminate the service reconnection fees for residential customers; (3) increase the service reconnection fees for commercial customers to $50.00;[167] and (4) eliminate the meter testing fees currently charged by Essex Gas and Colonial Gas (Exhs. NG-AEL-1, at 20-21; DPU-2-22).

During the test year, National Grid booked reconnect fees and bad check fees as follows: (1) $266,216 to Boston Gas/Essex Gas; and (2) $114,050 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial Gas (Rev. 3) at 4). National Grid's proposed changes to these administrative fees and charges result in a net $9,262 reduction to test year revenues for Boston Gas-Essex Gas and a net $23,290 reduction to test year revenues for Colonial Gas (Exhs. NG-AEL-1, at 14, 15; NG-AEL-2, at 18, 32; NG-MDL-2-Boston Gas (Rev. 3) at 4, 5; NG-MDL-2-Colonial Gas (Rev. 3) at 4, 5). No other parties commented on the proposed adjustments.

2. Analysis and Findings

Fees for ancillary services, such as returned check charges and disconnection fees, are intended to reimburse a company for actual costs incurred in providing these particular services. D.P.U. 08-35, at 58. The Department has found that these types of fees must be based on the costs incurred by the company in performing these particular tasks. See, e.g.,

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166 Essex Gas currently assesses a $15.00 returned check charge and Colonial Gas currently assesses a $10.00 returned check charge (Exh. DPU-2-22).

167 Essex Gas currently charges a $12.00 service reconnection fee for commercial customers and Colonial Gas currently charges a $25.00 service reconnection fee for commercial customers (Exh. DPU-2-22).

D.T.E. 08-35, at 58; Whitinsville Water Company, D.P.U. 89-67, at 4 (1989); Commonwealth Electric Company, D.P.U. 956, at 62 (1982).

The Companies currently operate on a consolidated basis (Exh. DPU-9-7). As such, we find that standardizing the administrative fees and charges will simplify the Companies' tariffs, facilitate the ability of customers to obtain correct information on service fees, and reduce the administrative cost associated with maintaining separate charges and fees. See, e.g., Massachusetts-American Water Company, D.P.U. 95-118, at 84 (1996).

We have reviewed National Grid's calculations and assumptions and find that the proposed fees and charges are supported by the record (Exhs. NG-AEL-2, at 18, 32; DPU-2-21). Therefore, the Department approves National Grid's proposed adjustments which will reduce test year revenues for Boston Gas-Essex Gas by $9,262 and reduce test year revenues for Colonial Gas by $23,290.

H. Demand Side Management Incentive Adjustment

1. Introduction

The Companies propose a demand side management ("DSM") incentive adjustment to remove the amount of revenue recorded by the Companies in relation to the incentives they achieved for the successful implementation of their DSM programs (Exh. NG-AEL-1, at 12). During the test year, National Grid booked revenues from DSM incentives as follows: (1) $1,197,873 to Boston Gas-Essex Gas; and (2) $333,256 to Colonial Gas (Exhs. NG-AEL-1, at 12; NG-AEL-2, at 1, 19; NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial Gas (Rev. 3) at 4; DPU-2-14). According to National Grid, the incentive revenues collected from customers in the period January through October 2009 are based on DSM incentives earned during the period May through December 2007, and incentive revenues collected in the months of November and December 2009 are based on DSM incentives earned during the period January through December 2008 (Exh. DPU-2-14). National Grid proposes to remove these amounts from the Companies' test year revenues (Exh. NG-AEL-1, at 12). No party commented on the proposed adjustments.

2. Analysis and Findings

The proposed DSM incentive adjustment represents the amount of revenue earned by the Companies in relation to the incentives they achieve for the successful implementation of their DSM programs. These revenues are not directly associated with distribution rates. D.T.E. 03-40, at 15. As such, in order to establish a representative level of annual revenues for the establishment of base rates, the Companies must remove from operating revenues the amount of DSM incentive payments collected. D.T.E. 03-40, at 15. After review, we find that National Grid correctly calculated the proposed adjustment to remove revenues collected during the test year to recover DSM incentive payments (See Exh. DPU-2-14). Therefore, the Department approves National Grid's proposed DSM incentive adjustments which reduce test year revenues for Boston Gas-Essex Gas by $1,197,873 and reduce test year revenues for Colonial Gas by $333,256.

I. Optimization and Other Off-System Sales Adjustment

1. Introduction

During the test year, National Grid booked revenues derived from interruptible sales and interruptible transportation and off-system sales as follows: (1) $89,770,508 to Boston Gas-Essex Gas; and (2) $8,644,689 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial (Rev. 3) at 4). National Grid proposes to make an optimization and other off-system sales adjustment to remove these amounts from the Companies' test year revenues. No other parties commented on the proposed adjustments (Exhs. NG-AEL-1, at 12; NG-AEL-2, at 1, 19; NG-MDL-2-Boston Gas (Rev. 3) at 4, 5; NG-MDL-2 Colonial Gas (Rev. 3) at 4, 5).

2. Analysis and Findings

National Grid's interruptible sales and transportation contracts are distinct from distribution base rates. These non-firm sales are not directly associated with distribution base rates. Accordingly, to establish a representative level of the Companies' annual revenues to establish base rates, National Grid must remove non-firm revenues from total operating revenues. After review, we find that National Grid has properly calculated its proposed adjustments to remove from test year revenue calculations, revenues derived from interruptible sales and interruptible transportation and off-system sales (Exhs. NG-AEL-2, at 1, 19; NG-MDL-2-Boston Gas (Rev. 3) at 4, 5; NG-MDL-2 Colonial Gas (Rev. 3) at 4, 5; DPU-2-16). Therefore, the Department approves National Grid's proposed adjustments which reduce test year revenues for Boston Gas-Essex Gas by $89,770,508 and reduce test year revenues for Colonial Gas by $8,644,689.

J. Gain on Sale of Property

1. Introduction

On December 29, 2003, Colonial Gas sold its former headquarters at 40 Market Street in Lowell, Massachusetts to a non-affiliated realty trust, at a total price of $1,588,654 (Exh. AG-1-20, at 2; RR-AG-37). The book value of the property at the time of the sale was $1,439,975, resulting in a gain of $148,667, all of which was attributed to the land (RR-AG-37).[168] Colonial Gas recorded the proceeds as income (Exhs. AG-1-20, at 2; RR-AG-37). National Grid has not proposed any adjustment to account for the gain on the sale of this property.

2. Position of the Parties

The Attorney General argues that Department precedent requires that National Grid return to ratepayers the net gains on the sale of Colonial Gas' former headquarters (Attorney General Brief at 103-104, citing D.P.U. 95-118, at 142-143; Commonwealth Electric Company, D.P.U. 88-135/151, at 91 (1989); Boston Gas Company, D.P.U. 1100, at 62-65 (1982)). The Attorney General contends that the return of the net proceeds to ratepayers is required because shareholders already have earned a fair return of and on those assets

[168] Pursuant to the USOA-Gas, any gain on the sale of depreciable property is charged against the depreciation reserve. 220 C.M.R. § 50 (Gas Plant Instructions at 9(B), 9(F)). Gains on the sale of land are booked to Account 434 - Miscellaneous Credits to Surplus. 220 C.M.R. § 50 at 9(E).

(Attorney General Brief at 104). The Attorney General asserts that a five-year amortization period is a reasonable time over which to return to customers the net gain on the sale of Colonial Gas' former headquarters (Attorney General Brief at 104).

3. Analysis and Findings

The Department's long-standing policy with respect to gains on the sale of utility property is to require the return to ratepayers of the entire gain associated with the sale if those assets were recorded above-the-line and supported by ratepayers. D.P.U. 08-35, at 138; D.P.U. 96-50 (Phase I) at 111; Barnstable Water Company, D.P.U. 93-233-B at 12-13 (1994). Therefore, if such property is sold by the utility, it is necessary to include an adjustment that recognizes the appreciation on assets that ratepayers have supported in rates through a return of and on the investment. D.P.U. 88-135/151, at 91. As an asset, Colonial's headquarters would have been recorded above-the-line and supported by ratepayers. Colonial Gas Company, D.P.U. 84-94, at 20-21 (1984). Accordingly, the Department finds that it is necessary to return the net proceeds, $148,667, from the sale of this asset to ratepayers (see Exhs. AG-1-20; RR-AG-37).

The Attorney General proposes a five-year amortization period for the gain on sale of Colonial's headquarters (Attorney General Brief at 103-104). In order to determine the appropriate number of years over which to return the proceeds from asset sales to customers, the Department balances the interests of Colonial Gas and the ratepayers. See D.P.U. 93-233-B at 14. The Department has considered such factors as the amount under consideration for amortization, the value of such an amount to ratepayers based on certain amortization periods, and the impact of the adjustment on the company's finances and incomes. See, e.g., D.P.U. 93-233-B at 14; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 54 (1985).[169] Based on these considerations and the record in this case, the Department finds five years to be an appropriate amortization period. A five-year amortization period, applied to the $148,667 gain on the sale of Colonial Gas' headquarters, produces an annual amortization amount of $29,733. Accordingly, Colonial Gas' test year revenues will be increased by $29,733.

K. Special Contracts

1. Introduction

National Grid currently has over 75 individually-negotiated special contracts with entities that have alternate fuel and do not wish to take service under National Grid's firm delivery service tariff (Exhs. AG-1-99; AG-2-99; AG-3-99; Tr. 10, at 1320). Special contracts also are needed when customers take supply under a firm delivery service tariff but have the ability to bypass the tariff and use an alternative fuel (Tr. 10, at 1320-1323). For ratemaking purposes, National Grid credits all test year revenues from special contracts to firm delivery service customers (Exh. DPU-16-26, at 1).

During the test year, special contract revenues were booked as follows: (1) $20,249,408 to Boston Gas-Essex Gas; and (2) $527,888 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial Gas (Rev. 3) at 4). National Grid

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169 Although determination of an appropriate amortization period is case-specific, the Department has generally found amortization periods in the range of three to six years to be reasonable. See, e.g., D.P.U. 08-35, at 139-140; Boston Edison Company, DP.U. 85-266-A/271-A at 33-34 (1986).

did not propose to make any adjustment for special contract revenues (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 4; NG-MDL-2-Colonial Gas (Rev. 3) at 4; Tr. 10, at 1320).

2. Position of the Parties

a. Attorney General

The Attorney General contends that National Grid may be understating revenues by not adjusting for known and measurable changes to the test year level of special contract revenues (Attorney General Brief at 106). The Attorney General proposes that National Grid be required to include, in its compliance filing, an adjustment to test year special contract revenues to reflect all annualized known and measurable changes to revenues for special contracts that have been approved by the Department prior to the date of the Order in this case, including recently approved contracts with the Medical Area Total Energy Plant, LLC ("MATEP"), the Sisters of Notre Dame, and Hanscom Air Force Base (id.).[170] The Attorney General argues that the change in special contract revenues is significant, referencing one Boston Gas special contract renewal ("Boston Gas/Boston University special contract") approved by the Department during 2010 that will provide approximately $2.0 million in additional revenues per year resulting from the doubling of a demand charge (Attorney General Reply Brief at 47).

[170] These special contracts were approved by the Department in Boston Gas Company/MATEP, D.P.U. 10-GC-14 (2010), Essex Gas Company/Sisters of Notre Dame, D.P.U. 10-GC-16 (2010), and Boston Gas Company/Hanscom Field, D.P.U. 10-GC-17 (2010). Pursuant to 220 C.M.R. § 1.10(3), the Department, on its own motion, incorporates by reference these special contracts and makes them part of the record in this proceeding.

b. National Grid

National Grid submits that the Department has approved 15 special contracts since the end of the test year; of these, twelve were contract renewals where the original contracts were in place in the test year and are included in the revenue requirement; only three are new contracts, of which two will produce net margins for the system of less than $100,000 per year on a combined basis (National Grid Reply Brief at 90, citing Exhs. AG-1-99; AG-4-3; AG-4-3 (Supp.)). According to National Grid, the third new contract, the Boston Gas/Boston University special contract, entails larger volumes but will require post-test year capital costs to bring the customer on line (National Grid Reply Brief at 90).

National Grid further contends that, of the twelve special contracts that were in place during the test year (and are included in the test-year revenue requirement), only one contract is anticipated to produce noticeable incremental revenues (i.e., the Boston Gas special contract identified by the Attorney General) (National Grid Reply Brief at 90, citing Attorney General Reply Brief at 47). National Grid submits that the incremental revenues associated with this Boston Gas contract are expected to total approximately $2.0 million annually, which represents 0.37 percent of National Grid's total distribution revenues (National Grid Reply Brief at 90).

National Grid states that the incremental revenues associated with each of the remaining eleven contracts range from approximately $4,000 to $92,000 (National Grid Reply Brief at 90). Further, National Grid contends that, in total, the incremental revenues associated with post-test year sales growth for special contract revenues equal $2.7 million, exclusive of the

Boston Gas/Boston University special contract (National Grid Reply Brief at 90). National Grid submits that the $2.7 million in special contract revenues equates to only 0.50 percent of National Grid's total distribution revenues which, National Grid asserts, is less than any post-test year revenue adjustment ever mandated by the Department (National Grid Reply Brief at 90).

Accordingly, National Grid argues that the Attorney General's recommended revenue adjustment should be rejected because (1) adjustments are not normally made for post-test year changes in revenues associated with customer growth; (2) the changes in special contract revenues occurring since the test year do not constitute a "significant change" outside of the "ebb and flow" of customers; and (3) commencement of service under the aforementioned Boston Gas contract will require a capital contribution by National Grid on or after January 1, 2010, and the associated capital costs will not be included in rates (National Grid Brief at IX.11-12; National Grid Reply Brief at 89, 91).

3. Analysis and Findings

a. Standard of Review

The Department seeks to include in rates the likely cost of providing the same level of service as was provided in the test year. D.T.E. 99-118, at 17; D.P.U. 88-67 (Phase I) at 140. Therefore, the Department does not normally make adjustments for post-test year changes in revenues attributed to customer growth unless the change is significant and outside of the normal "ebb and flow" of customers. D.T.E. 03-40, at 27; D.T.E. 02-24/25, at 77; Massachusetts American Water Company, D.P.U. 88-172, at 7-8; Bay State Gas Company, D.P.U. 1122, at 46-49 (1982). The rationale for this policy is that revenue adjustments of this nature would also require a number of corresponding adjustments to expense and could disrupt the relation of test year revenues to test year expenses. D.T.E. 03-40, at 27; New England Telephone and Telegraph Company, D.P.U. 86-33-G at 322-327 (1989). However, the addition or deletion of a customer or a change in a customer's consumption, either during or after the test year, that (1) represents a known and measurable increase or decrease to test year revenues and (2) constitutes a significant change outside of the "ebb and flow" of customers, may warrant an adjustment. D.T.E. 03-40, at 28. A change can be significant in one set of circumstances and insignificant in another. In cases where a significant change is found to exist, the Department may include (or exclude) a representative level of sales corresponding to a proven change in the derivation of a utility's revenue requirement. D.T.E. 03-40, at 28; D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14-20; D.P.U. 88-172, at 7-9. In making the "ebb and flow" determination, the Department has consistently considered the effect on a company's total distribution operating revenues. See D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 18. Total distribution revenues are the standard for comparison – not some subset such as special contracts. See, e.g., D.T.E. 02-24/25, at 80-81.

In addition, post-test year increases in special contract revenues may result from an increase in the rate charged under a specific contract, as opposed to a change in load. See, e.g., D.T.E. 05-27, at 59-60. In such circumstances, the Department has approved post-test year adjustments to special contract revenues resulting from known and measurable changes in contract pricing terms. See D.T.E. 05-27, at 59-60.

b. Post-Test Year Special Contracts - New Customers

National Grid has entered into three new post-test year special contracts.[171] The first contract is the Boston Gas/Boston University special contract, D.P.U. 10-GC-1 (2010). This contract will require a capital investment by National Grid and it is expected that Boston Gas can commence service under the contract upon completion of necessary system enhancements, currently projected to be November 1, 2010 (Exh. AG-4-3 (Supp)). Because the rates approved in this proceeding do not include the cost of the capital contribution that will be necessary to commence service pursuant to this contract, we find that it is not appropriate to include the Boston Gas/Boston University special contract revenues in rates.

The remaining two new contracts are expected to generate revenues totaling less than $100,000.[172] The Department is not persuaded that, in these circumstances, such an increase in revenues is significant enough to fall outside normal the ebb and flow of business. See, e.g., D.T.E. 03-40, at 30-31; D.T.E. 02-24/25, at 80-83; D.T.E. 99-118, at 18. Further, this level of incremental revenues represents such a small fraction of Boston Gas-Essex Gas' total distribution revenues that an adjustment to account for these new revenues is unwarranted. See

[171] These contracts are: (1) Boston Gas Company/Boston University, D.P.U. 10-GC-1 (2010) (see Exh. AG-4-3 (Supp.), Att.); (2) Boston Gas Company/Faulkner Hospital, D.P.U. 10-GC-10 (2010); and (3) Boston Gas Company/Global Industries, D.P.U. 10-GC-8 (2010). The Department, on its own motion, pursuant to 220 C.M.R. § 1.10(3), incorporates by reference the Faulkner Hospital and Global Industries contracts and makes them part of the record in this proceeding.

[172] Given that the Department accorded the pricing terms of these contracts protective treatment pursuant to G.L. c. 25, § 5D in their respective dockets, we will not present the detailed calculations here.

D.T.E. 03-40, at 28; D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14-20. Accordingly, the Department will not adjust the Companies' revenues to account for the revenues expected to be generated by these three new special contracts.

c. Post-Test Year Special Contracts - Renewals

The Department has identified 18 special contracts that are post-test year renewals, including special contracts that were filed with and approved by the Department in separate dockets during the course of this proceeding (Exhs. AG-1-99; AG-4-3; AG-4-3 (Supp.); AG-23-2; AG-31-19).[173] We find that there is an annualized known and measurable change in revenues associated with these special contract renewals because new pricing terms have been approved by the Department. The Department calculates the total revenue change as

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173 Five of these special contracts are part of the record in this case: Colonial Gas Company/Aggregate Industries – Northeast Region, Inc., D.P.U. 10-GC-3 (2010); Boston Gas Company/Beverly Hospital, D.P.U. 09-GC-24 (2010); Boston Gas Company/Boston College, D.P.U. 09-GC-23 (2009); Boston Gas Company/Newton Wellesley Hospital, D.P.U. 09-GC-22 (2009); and Boston Gas Company/Brookhouse Condominium Trust, D.P.U. 09-GC-21 (see Exhs. AG-1-99(1); AG-1-99(3); AG-1-99 (45); AG-1-99(58); and AG-1-99(61)). Of the 13 remaining contracts, three were incorporated by reference into this record above in n. 171. The Department, on its own motion, pursuant to 220 C.M.R. § 1.10(3), incorporates the eight contracts from the following dockets and makes them part of the record in this proceeding: (1) Boston Gas Company/Harrington Memorial Hospital, D.P.U. 09-GC-25 (2010); (2) Boston Gas Company/Bunker Hill Community College, D.P.U. 10-GC-6 (2010); (3) Boston Gas Company/McLean Hospital, D.P.U. 10-GC-9 (2010); (4) Boston Gas Company/First Church of Christ Scientist, D.P.U. 10-GC-11 (2010); (5) Boston Gas Company/Kraft – Atlantic Gelatin, 10-GC-12 (2010); (6) Boston Gas Company/Certainteed, D.P.U. 10-GC-13 (2010); (7) Boston Gas Company/Salem State College, D.P.U. 10-GC-18 (2010); (8) Boston Gas Company/Braintree Electric and Light Company, D.P.U. 10-GC-19 (2010); (9) Boston Gas Company/Massachusetts Port Authority, D.P.U. 10-GC-20 (2010); and (10) Boston Gas Company/Northeastern University, D.P.U. 10-GC-21 (2010).

$3,804,571.[174] The increase to test year revenues serves to reduce the revenue requirement, as special contract revenues are credited to the cost of service. Accordingly, the Department will increase the test year revenues of Boston Gas-Essex Gas by $3,801,385 and increase the test year revenues of Colonial Gas by $3,186.

X. OPERATING AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

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

174 The new demand and volumetric revenues were calculated by applying the new pricing terms in the 16 contract renewals to the 2009 test year gas consumption volumes for each respective special contract customer. Given that the Department accorded the pricing terms for these contracts protective treatment pursuant to G.L. c. 25, § 5D in their respective dockets, we will not present the detailed calculations here.

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

National Grid's employee compensation program is known as the "Total Rewards Program" (Exh. NG-MES-1, at 4-5). The Total Rewards Program encompasses base pay, variable pay, medical and dental insurances, life and long-term disability insurances, vacation and holiday pay, a pension plan,[175] a 401(k) plan, and post-retirement benefits (Exh. NG-MES-1, at 4-5, 23).

2. Employee Staffing Levels

a. Introduction

In calculating changes in staffing levels during the test year, Boston Gas-Essex Gas and Colonial Gas calculated the wage expense based on the employee count as of December 31, 2009 (Exhs. NG-MDL-1, at 19, 21, 62, 64; NG-MDL-2-Boston Gas at 14-17; NG-MDL-2-Colonial Gas at 14-17). As of the end of the test year, Boston Gas-Essex Gas had 68 direct management employees and 909 direct union employees in bargaining units, for a total of 977 employees (Exhs. NG-MDL-2-Boston Gas at 14; AG 1-44, Att.). On that same

[175] Pension and post-retirement benefits other than pension are addressed in Section X.F, below.

date, Colonial Gas had 15 direct management employees and 165 direct union employees in bargaining units, for a total of 180 employees (Exh. NG-MDL-2-Colonial Gas at 14). In addition to these direct employees, KeySpan Corporate Services had 1,751 management and 1,651 union bargaining unit employees, KeySpan Utility Services had 115 management and 53 union bargaining unit employees, and National Grid USA Service Company, Inc. ("NGSC") had 2,336 management and 561 union bargaining unit employees (Exhs. NG-MDL-2-Boston Gas at 15-17; NG-MDL-2-Colonial Gas at 15-17).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that National Grid has overinflated its revenue requirement by using the number of employees at the end of the test year to determine pro forma adjustments (Attorney General Brief at 114, citing Exhs. NG-MDL-2-Boston Gas at 14-17, column (a); NG-MDL-2-Colonial Gas at 14-17, column (a)). The Attorney General maintains that the overstatement of these costs affects wages and salaries, incentive compensation, medical and dental insurance costs, and payroll taxes (Attorney General Brief at 114). The Attorney General argues that because the number of employees fluctuates over time, National Grid should have based its cost of service adjustments on the embedded average number of employees during the test year as the basis for all employee costs (Attorney General Brief at 114, citing Exh. AG-1-44; D.P.U. 09-30, at 192-193; Nantucket Electric Company, D.P.U. 88-161/168, at 66-67 (1988)). The Attorney General contends that the use of employee numbers at a single point in time allows National Grid to take advantage of what may be temporary increases, which ultimately leads to an overstatement of costs (Attorney General Brief at 115, citing Exh. AG-1-44).

The Attorney General asserts that Boston Gas-Essex Gas had, on average, 878 employees during the twelve months of 2009, which is 42 employees less than the year-end amount National Grid used for its proposed employee cost adjustments (Attorney General Brief at 114, citing Exh. AG-1-44). The Attorney General maintains that Colonial Gas had, on average, 171 employees during the twelve months of 2009, which is nine employees less than the year-end amount National Grid used for its proposed employee cost adjustments (Attorney General Brief at 114-115, citing Exh. AG-1-44). As a result, the Attorney General argues that Boston Gas-Essex Gas' cost of service should be reduced by $2,730,280 and Colonial Gas' cost of service should be reduced by $601,731 to reflect the average number of employees during the test year (Attorney General Brief at 115-116, citing Exhs. AG-1-101(A) (Rev. 2) at 10, line 1; NG-MDL-2-Colonial (Rev. 2), at 10, line 1).[176]

ii. National Grid

National Grid argues that it appropriately annualized and adjusted its payroll costs based on the test year-end number of employees consistent with Department precedent

176 To arrive at her proposed reduction to cost of service, the Attorney General first took the total proposed expense and divided it by the number of employees at test year-end to arrive at the average rate year of salary and wage expense. She then multiplied the average rate year of salary and wage expense by the number of employees that she proposes to remove from cost of service. Specifically, the calculations are as follows: (1) for Boston Gas-Essex Gas, $59,806,125 / 920 employees = $65,007, and $65,007 x 42 employees = $2,730,280; and (2) for Colonial Gas, $12,034,623 / 180 employees = $66,859, and $66,859 x nine employees = $601,731 (Attorney General Brief at 115-116).

(National Grid Brief at IX.24, citing D.P.U. 09-30, at 189-190; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 16-17 (1983)). National Grid further asserts that the test year-end number of employees is the best indicator of the number of employees that Boston Gas-Essex Gas and Colonial Gas will employ on a going-forward basis, especially given that employee staffing level projections for 2010 are comparable to the test year-end employee counts for Boston Gas-Essex Gas and Colonial Gas (National Grid Brief at IX.25, citing Exh. AG-1-44).

National Grid accepts that the Department has required an adjustment to staffing levels where a company has undergone a structural change, however, it argues that a structural change has not occurred here (National Grid Brief at IX.24, citing D.T.E. 09-30, at 192). Instead, National Grid contends that the evidence demonstrates that the number of employees working directly for Boston Gas-Essex Gas and Colonial Gas has increased by 22 percent and 23 percent, respectively, in the three-year period from 2007 to 2009, in order to achieve compliance with the Department's seven-year meter change-out program (National Grid Brief at IX.24-25, citing Exhs. AG-33-3; AG-33-4).

c. Analysis and Findings

Employee staffing levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. D.P.U. 88-172, at 12; D.P.U. 1270/1414, at 16-17. In recognition of this variability, the Department generally determines payroll expense 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. The Berkshire Gas Company, D.P.U. 90-121, at 80-81 (1990); D.P.U. 88-172, at 12.

The Attorney General asserts that the use of employee numbers from a single point in time allows the Companies to take advantage of what may be temporary increases (Attorney General Brief at 115). National Grid had shown, however, that the increases are not temporary. Between 2007 and the end of 2009, Boston Gas-Essex Gas and Colonial Gas gradually increased employee staffing levels (Exhs. AG-1-44; AG-33-3; AG-33-4). The evidence further demonstrates that the increases are primarily to achieve compliance with the Department's seven-year meter change-out schedule and to conduct service replacements, which increased from 500 per year to approximately 5,000 per year between 2007 and 2009 (Exhs. AG-33-3; AG-33-4). Thus, we find the Companies' use of the employee complement at test year-end is reasonable.

3. Union Wage Increases

a. Introduction

During the test year, National Grid booked $84,631,178 in payroll expenses for union personnel, including base wages, variable pay, and overtime pay (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 12; NG-MDL-2-Colonial Gas (Rev. 3) at 12). Boston Gas-Essex Gas booked $70,446,549 in union payroll expenses, of which $56,145,779 was directly incurred, $13,632,015 was allocated from KeySpan Corporate Services, $42,503 was allocated from KeySpan Utility Services, and $626,252 was allocated from NGSC (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 12). Colonial Gas booked $14,184,629 in union payroll expenses, of which

$10,438,742 was directly incurred, $3,269,089 was allocated from KeySpan Corporate Services, $9,542 was allocated from KeySpan Utility Services, $101,460 was allocated from NGSC, and $365,796 was allocated from other National Grid companies (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 12).

National Grid proposes adjustments to increase the Companies' test-year union payroll expense to account for (1) increased staffing levels; and (2) increases required by the currently-effective collective bargaining agreements (Exhs. NG-MES-1; NG-MES-3; AG 33-3; AG 33-4). Boston Gas-Essex Gas increased its test year union payroll expense by $2,557,005, attributable as follows: (1) $2,176,899 in direct costs; (2) $361,248 allocated from KeySpan Corporate Services; (3) $446 allocated from KeySpan Utility Services; and (4) $18,412 allocated from NGSC (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 12). Colonial Gas increased its test year union payroll expense by $532,317, attributable as follows: (1) $442,603 in direct costs; (2) $86,631 allocated from KeySpan Corporate Services; (3) $100 allocated from KeySpan Utility Services; and (4) $2,982 allocated from NGSC (Exh. NG-MDL-2-Colonial (Rev. 3) at 12). No party commented on this issue.

b. Analysis and Findings

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the 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. 96-50 (Phase I) at 43 (1996); Massachusetts Electric Company, D.P.U. 95-40, at 20 (1995); D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 74 (1987). Pursuant to collective bargaining agreements, all union payroll rates will have increased during 2010 and three additional union payroll rate increases will be in effect prior to the midpoint of the first twelve months after issuance of the Department's Order in this proceeding (i.e., April 30, 2011) (Exhs. NG-MES-1, at 13-14; NG-MES-3). As the union rate increases are based on ratified agreements (see Exhs. NG-MES-1, at 13-14; AG 1-42, Att.; RR-AG-39) the Department finds that they are known and measurable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20.

In addition, National Grid submitted a comparison of its union salaries to utilities throughout the Northeast (Exh. NG-MES-2). The hourly rates paid by National Grid for specific job titles are comparable to the hourly rates paid by other gas companies in the area (Exh. NG-MES-2). Thus, we find that National Grid has demonstrated the reasonableness of its union pay increases.

Having found that the union rate increases (1) take effect prior to the midpoint of the first twelve months after the rate increase, (2) are known and measurable, and (3) are reasonable, the Department approves National Grid's proposed adjustments to union payroll expense.

4. Non-Union Wage Increases

a. Introduction

During the test year, National Grid booked $33,058,506 in payroll expenses for non-union personnel, including base wages, variable pay, and overtime pay

(Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 13; NG-MDL-2-Colonial Gas (Rev. 3) at 13). Boston Gas-Essex Gas booked $26,758,529 in non-union payroll expenses, of which $4,154,356 was directly incurred, $18,911,272 was allocated from KeySpan Corporate Services, $87,298 was allocated from KeySpan Utility Services, $3,594,967 was allocated from NGSC, and $10,636 was allocated from other National Grid companies (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 13). Colonial Gas booked $6,299,976 in non-union payroll expenses, of which $937,524 was directly incurred, $4,575,354 was allocated from KeySpan Corporate Services, $19,663 was allocated from KeySpan Utility Services, $581,916 was allocated from NGSC, and $185,520 was allocated from other National Grid companies (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 13).

The Companies propose to increase test year non-union payroll expense by $755,833 to account for increases that were effective July 1, 2010, and thus occurred after the end of the test year (Exhs. NG-MES-1, at 16; NG-MDL-2-Boston Gas (Rev. 3) at 13; NG-MDL-2-Colonial Gas (Rev. 3) at 13). Boston Gas-Essex Gas increased its test year non-union payroll expense by $615,201, attributable as follows: (1) $95,550 in direct costs; (2) $434,958 allocated from KeySpan Corporate Services; (3) $2,008 allocated from KeySpan Utility Services; and (4) $82,684 allocated from NGSC (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 13). Colonial Gas increased its test year non-union payroll expense by $140,632, attributable as follows: (1) $21,563 in direct costs; (2) $105,233 allocated from KeySpan Corporate Services; (3) $452 allocated from KeySpan Utility Services; and (4) $13,384 allocated from NGSC (Exh. NG-MDL-2-Colonial (Rev. 3) at 13). No party commented on this issue.

b. Analysis and Findings

To recognize an adjustment for an increase in non-union wages that takes place prior to the issuance of an Order, the Company must demonstrate that such increases are known and measurable and also reasonable.[177] See D.P.U. 08-35, at 81-82, 87; D.P.U. 92-250, at 35; D.P.U. 1270/1414, at 14. To recognize an adjustment for an increase in non-union wages that may occur post-Order, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; D.P.U. 1270/1414, at 14. In addition, only non-union salary increases that are scheduled to become effective no later than the midpoint of the first twelve months after the date of the Order may be included in rates. Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986).

National Grid has provided sufficient evidence to demonstrate that it has expressly committed to granting a 2.3 percent non-union wage increase effective July 2010 (Exhs. NG-MES-1, at 16; NG-MES-5; AG-15-44, Att.; Tr. 14, at 1932-1934). Accordingly, the Companies' proposed adjustments include only those increases that have been granted

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177 One indicia of reasonableness the Department will consider is whether there is an historical correlation between union and non-union raises. See, e.g., D.P.U. 09-30, at 186; D.P.U. 08-35, at 81-82; D.P.U. 87-59, at 32; D.P.U. 1270-1414, at 14.

before the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. NG-MES-1, at 16; NG-MS-5).

In support of the historical correlation between union and non-union wage increases, National Grid provided a comparative analysis of union and non-union wage increases between 2001 and 2010 (Exh. NG-MES-6). Between 2001 and 2010, annual union wage increases were between 2.5 percent and 3.25 percent and annual non-union increases were between 1.5 percent and 4.55 percent (Exh. NG-MES-6). Between 2001 and 2005, annual union wage increases were between 2.5 percent and 3 percent and annual non-union increases were between 2.75 percent and 4.25 percent. Between 2006 and 2010, annual union wage increases were between 2.5 percent and 3.25 percent and annual non-union increases were between 1.5 percent and 4.55 percent (Exh. NG-MES-6). In looking at the last five years, we determine that there is a strong correlation between union and non-union wage increases. Thus, the Department finds that a sufficient correlation exists between union and non-union wage increases. See D.P.U. 09-30, at 189; Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

With respect to a demonstration of the reasonableness of the proposed non-union salary increase, National Grid undertakes annual external benchmarking to determine market practice relating to management salary increases (Exhs. NG-MES-1, at 14; AG-15-44). Specifically, National Grid reviews reports from external consultants, attends external seminars, and participates in annual salary surveys and uses the resulting data to assess the competitiveness of salary levels (Exh. AG-15-44; see NG-MES-4). National Grid has demonstrated that its non-union compensation levels are competitive with comparable positions in (1) companies with revenues greater than $6 billion nationwide, and (2) regional energy service companies in the Northeast (Exh. NG-MES-1, at 16-17; NG-MES-4). The Department finds that National Grid's review of industry compensation data is sufficient to confirm the reasonableness of its salary levels. See D.T.E. 05-27, at 110; D.T.E. 02-24/25, at 94-95 (2002). Therefore, the Department approves National Grid's proposed adjustments to test year cost of service for Boston Gas-Essex Gas and Colonial Gas for the non-union payroll increases.[178]

5. Incentive Compensation

a. Introduction

In 2007, National Grid introduced a variable pay program and began converting a portion of employees' base pay to incentive compensation (Exhs. NG-MES-1, at 17-19; AG-1-35; AG-15-20; see Exh. AG-30-70).[179] There are two components to the incentive

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178 During the proceeding, National Grid removed $722,943 and $82,161 from its test year cost of service for Boston Gas-Essex Gas and Colonial Gas, respectively, for expatriate employees' payroll related costs and employee reimbursements (Exhs. NG-MDL-2-Boston Gas (Rev. 3) (Changes Identified Post Filing); NG-MDL-2-Colonial Gas (Rev. 30 (Changes Identified Post Filing)). Specifically, the Companies removed $617,769 and $75,005 for Boston Gas-Essex Gas and Colonial Gas, respectively, for expatriate employees' payroll related costs, and $105,174 and $7,156 for Boston Gas Essex Gas and Colonial Gas, respectively, for employee reimbursements (Exhs. NG-MDL-2-Boston Gas (Rev. 3) (Changes Identified Post Filing); NG MDL 2 Colonial Gas (Rev. 30 (Changes Identified Post Filing); RR-AG-71). The Department removed these from the test year costs of service as a single line item labeled "Expatriate, Officer, Director Expenses" on Schedule 2 (Boston Gas-Essex Gas) and Schedule 2 (Colonial Gas), below.

179 National Grid states that, since the introduction of its variable pay program in 2007, it has been expanding the program throughout the organization and that, by the end of

compensation program: (1) performance metrics focused on overall company financial health, including earnings per share, operating profit, and cash flow; and (2) performance metrics and goals focused on individual objectives of improving customer deliverables such as customer satisfaction, safety, and reliability (Exhs. NG-MES-1, at 6-7, 18; NG-MES-7, at 2, 11).

For the majority of non-union employees, 50 percent of incentive compensation is based on the financial component and 50 percent of incentive compensation is based on the individual objectives component (Exhs. NG-MES-1, at 6-7, 18; AG-15-4).[180] For union employees, the individual objectives relating to customer satisfaction, safety, and reliability account for 100 percent of incentive pay (Exh. NG-MES-1, at 6).

National Grid did not include in the proposed revenue requirement the variable component portion of overall executive compensation for executive and senior vice-presidents (Exhs. NG-MES-1, at 18; AG-38-12). During the test year, Boston Gas-Essex Gas booked $4,529,916 in incentive compensation for non-union employees attributable as follows: (1) $273,328 in direct costs; (2) $3,657,243 allocated from KeySpan Corporate Services; (3) $9,430 allocated from KeySpan Utility Services; (4) $589,375 allocated from NGSC; and (5) $541 allocated from other National Grid companies (Exhs. NG-MDL-1, at 22; NG-MDL-2-Boston Gas (Rev. 3) at 18). During the test year, Colonial Gas booked

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fiscal year 2009, the entire management population will take part in the variable pay program (Exh. AG-15-20).

180 For executive vice-presidents, senior vice-presidents, and vice-presidents, 60 percent of incentive compensation is based on the financial component and 40 percent of incentive compensation is based on individual objectives (Exhs. NG-MES-7, at 2; AG-15-4; AG-15-23; AG-15-47; AG-38-12).

$1,090,975 in incentive compensation for non-union employees attributable as follows: (1) $12,699 in direct costs; (2) $920,960 allocated from KeySpan Corporate Services; (3) $2,093 allocated from KeySpan Utility Services; (4) $123,030 allocated from NGSC; and (5) $32,193 allocated from other National Grid companies (Exh. NG-MDL-2-Colonial (Rev. 3) at 18).

National Grid proposes a decrease of $1,505,560 and $376,350 to the incentive compensation for Boston Gas-Essex Gas and Colonial Gas, respectively, based on targeted results for the test year,[181] resulting in proposed rate year incentive compensation for non-union employees of $3,024,357 for Boston Gas-Essex Gas and $714,625 for Colonial Gas (Exhs. NG-MDL-3-Boston Gas (Rev. 3) at 18; NG-MDL-2-Colonial Gas (Rev. 3) at 18).

During the test year, Boston Gas-Essex Gas booked $792,197 in incentive compensation for union employees attributable as follows: (1) $672,869 in direct costs; (2) $116,321 allocated from KeySpan Corporate Services; (3) $131 allocated from KeySpan Utility Services; and (4) $2,876 allocated from other National Grid companies (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 19). During the test year, Colonial Gas booked $179,332 in incentive compensation for union employees attributable as follows: (1) $150,649 in direct costs; (2) $25,062 allocated from KeySpan Corporate Services; (3) $33 allocated from

181 Under its variable pay plan, National Grid established financial targets, which are a percentage of the maximum award percentage (Exhs. AG-15-3; AG-15-4; AG-15-6). During the test year, the Companies exceeded the established targets and, thus, are proposing to decrease test year amounts to include only the targeted results (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 18; NG-MDL-2-Colonial Gas (Rev. 3) at 18; AG-15-3; AG-15-4; AG-15-6).

KeySpan Utility Services; and (4) $3,588 allocated from other National Grid companies (Exh. NG-MDL-2-Colonial (Rev. 3) at 19).

For union employees, National Grid proposes a decrease of $79,471 and $26,647 to the incentive compensation for Boston Gas-Essex Gas and Colonial Gas, respectively, based on targeted results for the test year, resulting in proposed rate year incentive compensation for union employees of $712,726 for Boston Gas-Essex Gas and $152,685 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 19; NG-MDL-2-Colonial Gas (Rev. 3) at 19).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should eliminate that portion of incentive compensation based on the attainment of financial goals because such incentives do not provide any benefits to customers (Attorney General Brief at 126, 129; Attorney General Reply Brief at 63-64). The Attorney General asserts that the attainment of financial targets, such as earnings or a rate of return, is a shareholder-oriented goal, rather than a customer-oriented goal and that, because shareholders are the primary beneficiaries of increases to earnings, shareholders should bear the cost of the incentive compensation related to earnings (Attorney General Brief at 126; Attorney General Reply Brief at 63-64).

The Attorney General argues that National Grid has not met its burden to demonstrate that its incentive compensation plan is consistent with Department precedent, which the Attorney General asserts permits plans that: (1) "rely on the achievement of financial goals to determine employee eligibility" so long as other factors are used to determine the actual level of compensation an employee may receive; and (2) are "reasonably designed to encourage good employee performance and will result in benefits to ratepayers" (Attorney General Brief at 128, citing D.P.U. 09-39; D.P.U. 08-35; Attorney General Reply Brief at 63). In asserting that National Grid's incentive compensation plan is not reasonably designed to encourage good employee performance, the Attorney General argues that it inappropriately permits employees to earn incentive compensation for the achievement of financial goals based on corporate behavior over which they had no influence (Attorney General Brief at 128-129, citing Tr. 14, at 1919).

ii. National Grid

National Grid argues that it has met the Department's standards for inclusion of incentive compensation in cost of service, which National Grid asserts is permitted as long as (1) the compensation is reasonable in amount, and (2) the plan is reasonably designed to encourage good employee performance (National Grid Brief at IX.27, citing D.P.U. 09-30, at 205; D.P.U. 08-35, at 97; D.T.E. 03-40, at 124; D.T.E. 02-24/25, at 99; National Grid Reply Brief at 105). National Grid contends that the incentive plan as proposed is consistent with Department precedent and is, in fact, the same plan approved by the Department in D.P.U. 09-39, at 141-142 (National Grid Brief at IX.27, 30, citing D.T.E. 03-40, at 124-125; D.T.E. 02-24/25, at 99-100; National Grid Reply Brief at 107). National Grid asserts that the Department found in D.P.U. 09-39 that recovery of incentive compensation through rates was reasonable because: (1) National Grid did not seek recovery of incentive compensation for its most senior executives; and (2) employee performance was adequately tied to meeting safety, reliability, and customer satisfaction goals (National Grid Brief at IX.30, citing D.P.U. 09-39, at 141-142).

National Grid also asserts that the incentive compensation levels paid to employees during the test year are reasonable (National Grid Brief at IX.28-29, citing Exhs. NG-MES-1, at 17-19; NG-MES-4; AG-15-4; AG-15-20; AG-15-24; AG-15-54(1); AG-15-54(2)). Specifically, National Grid asserts that its analysis of the Companies' base salaries and target total compensation compared to the market demonstrates that its incentive compensation costs are reasonable in amount (National Grid Brief at IX.28-29, citing Exhs. NG-MES-1, at 19; NG-MES-4, at 6). National Grid further contends that its incentive compensation costs are reasonable because the program is designed to motivate employees to ensure that: (1) safety, health, and environmental requirements are adhered to at all times; (2) standards of customer service are achieved; and (3) shareholder expectations are reached (National Grid Brief at IX.29, citing Exhs. NG-MES-1, at 17-18; AG-15-54(1); AG-15-54(2)).

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses (i.e., bonuses) to be included in utilities' cost of service so long as they are (1) reasonable in amount, and (2) the incentive plans are reasonably designed to encourage good employee performance. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 82-83 (2008); 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. Boston Gas Company, D.P.U. 93-60, at 99 (1993).

National Grid offers an incentive compensation plan for non-union employees that is based in part on the achievement of personal goals and in part on the achievement of financial goals (Exhs. NG-MES-1, at 18; NG-MES-7). National Grid offers an incentive compensation plan for union employees that is based entirely on the achievement of personal goals (Exh. NG-MES-1, at 6).

National Grid has not sought to recover incentive compensation for its executive and senior vice-presidents (Exh. NG-MES-1, at 18). Further, National Grid has conducted an analysis of base salaries and target total compensation compared to the market (Exhs. NG-MES-1, at 19-20; NG-MES-4). The Department finds that, based on the results of this study, National Grid has demonstrated that its incentive compensation costs are reasonable.

With respect to the design of incentive compensation plan, the Department finds that it is reasonably designed to encourage good employee performance. Specifically, the incentive compensation plan encourages good employee performance directly by rewarding non-union employees for achieving personal goals and also by contributing to the financial success of National Grid (Exhs. NG-MES-1, at 18-19; NG-MES-7).

Further, the Department finds that the incentive plan is reasonably designed to provide benefits to ratepayers. For the majority of non-union employees, 50 percent of variable pay is tied to meeting personal performance objectives (Exh. NG-MES-1, at 6; see Exh. AG-15-4 (Supp.)). For union employees, 100 percent of variable pay is tied to meeting personal performance objectives (Exh. NG-MES-1, at 6-7). Such performance objectives are tied to safety, reliability, and customer satisfaction and, therefore, are directly aligned with the interests of ratepayers (Exhs. NG-MES-1, at 18-19; NG-MES-7).

The remaining 50 percent of non-union variable pay is tied to meeting financial performance objectives (Exhs. NG-MES-1, at 6; AG-15-4 (Supp.)). Financial performance objectives (e.g., earnings per share, operating profit, and cash flow targets) are tied to National Grid's revenues and costs and, therefore, directly benefit shareholder interests. The benefits to ratepayers of meeting these financial targets are less direct.

The Attorney General correctly notes that financial performance has been a threshold determinant in incentive compensation plans approved by the Department. See D.P.U. 08-35, at 97-98; D.P.U. 02-24/25, at 101; D.P.U. 89-194/195, at 34. In these cases, once the financial performance threshold was met, job performance standards designed to encourage good employee performance were the basis for determining individual incentive compensation. D.P.U. 08-35, at 97-98; D.P.U. 02-24/25, at 101; D.P.U. 89-194/195, at 34. Financial performance, however, is not a threshold determinant in National Grid's incentive compensation plan.[182] Rather, financial performance is a significant component of the formula used to determine individual incentive compensation for non-union employees. Accordingly, the Attorney General argues that the incentive compensation plan is not reasonable in design because the attainment of financial targets, such as earnings or a rate of return, is not a

[182] The design of the plan, however, allows National Grid to forego partial payment during conditions of poor financial performance (Exhs. NG-MES-1, at 22; NG-MES-7, at 3, 13).

customer-oriented goal (Attorney General Brief at 126; Attorney General Reply Brief at 63-64).

As noted above, the attainment of financial targets has a primary and direct shareholder benefit and, therefore, we are concerned that these goals comprise such a large percentage of National Grid's incentive compensation plan design. Nonetheless, the Department recently approved the same incentive compensation structure in D.P.U. 09-39, at 142, finding that the benefit to ratepayers, although not clearly defined, is manifested in lower operating and capital costs. We approved the overall design of the incentive plan as reasonable because: (1) National Grid did not seek recovery of incentive compensation for its most senior executives; and (2) employee performance was adequately tied to meeting safety, reliability, and customer satisfaction goals. D.P.U. 09-39, at 142. For these same reasons, we find that the overall design of National Grid's incentive compensation plan is reasonable here (Exhs. NG-MES-1, at 17; NG-MES-7).[183]

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

Going forward, where companies seek to include financial goals as a component of incentive compensation program design, the Department would prefer to see the attainment of

183 We note that National Grid's incentive compensation plan permits it to reduce incentive payments to take account of significant safety issues, service standard incidents and environmental issues (Exh. NG-MES-7, at 4, 13).

such goals as a threshold component with job performance standards designed to encourage good employee performance (e.g., safety, reliability, and/or customer satisfaction goals) used as the basis for determining individual incentive compensation. Companies that wish to maintain the achievement of financial metrics as a direct component of an incentive compensation award must be prepared to demonstrate direct ratepayer benefit from the attainment of these goals or risk disallowance of the related incentive compensation costs.

6. Health and Dental Plans

a. Introduction

During the test year, Boston Gas-Essex Gas booked $12,547,280 in health and hospitalization costs, of which $8,131,365 were direct costs, $4,000,290 was allocated from KeySpan Corporate Services, $13,772 was allocated from KeySpan Utility Services, $391,540 was allocated from NGSC, and $10,313 was allocated from other National Grid companies (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 20). During the test year, Colonial Gas booked $3,103,042 in health and hospitalization costs, of which $1,862,633 were direct costs, $1,093,979 was allocated from KeySpan Corporate Services, $3,057 was allocated from KeySpan Utility Services, $75,763 was allocated from NGSC, and $67,610 was allocated from other National Grid companies (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 20).

National Grid proposes to remove$18,018 in costs related to strike contingency from Boston Gas-Essex Gas' test year health and hospitalization costs and $10,953 in costs related to construction work in progress ("CWIP") (Exh. NG-MDL-2-Boston Gas-Essex Gas (Rev. 3) at 30). According to National Grid, it charged the $18,018 directly to incremental strike contingency costs rather than recovering such expenses in health and hospitalization costs (see Exh. NG-MDL-6-Boston Gas WP 10; Tr. 8, at 1163-1164). National Grid states that the $10,953 in CWIP was removed from health and hospitalization costs because it originated in a prior period and, thus, should have been excluded from the test year O&M expenses (see Exhs. NG-MDL-1, at 15; NG-MDL-6-Boston Gas WP 7).

National Grid further proposes revisions as follows: (1) a reduction of $1,166,380 for Boston Gas-Essex Gas, of which $1,272,233 was directly allocated, net of $16,671 allocated from KeySpan Corporate Services, $1,840 allocated from NGSC, and $87,342 allocated from NGSC; and (2) a reduction of $564,049 for Colonial Gas, of which $416,931 was directly allocated, and $149,336 was allocated from KeySpan Corporate Services, net of $459 allocated from KeySpan Utility Services and $1,759 allocated from NGSC (Exhs. NG-MDL-1, at 23; NG-MDL-2-Boston Gas (Rev. 3) at 20; NG-MDL-2-Colonial Gas (Rev. 3) at 20). No party commented on this issue.

b. Analysis and Findings

To be included in rates, healthcare expenses must be reasonable. In addition, any post-test year adjustments to healthcare expense must be known and measurable.[184] The Berkshire Gas Company, D.T.E. 01-56, at 60 (2002); Boston Gas Company, D.P.U. 96-50

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184 A "known" change means that the adjustment must have actually taken place, or that the change will occur based on the record evidence, while a "measurable" change means that the amount of the required adjustment must be quantifiable on the record evidence. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 62 (1998). Proposed adjustments based on projections or estimates are not allowed. D.T.E. 98-51, at 62, citing The Berkshire Gas Company, D.P.U. 92-210, at 83 (1993); Dedham Water Company, D.P.U. 849, at 32-34 (1982).

(Phase I) at 46 (1996); North Attleborough Gas Company, D.P.U. 86-86, at 8 (1986). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; Massachusetts Electric Company, D.P.U. 92-78, at 29 (1992); Nantucket Electric Company, D.P.U. 91-106/138, at 53 (1991).

National Grid has provided sufficient evidence to demonstrate that its health and hospitalization expenses are reasonable in amount. Further, National Grid has shown that the proposed post-test year adjustments to remove costs related to strike contingency and CWIP are known and measurable (see, e.g., Exhs. NG-MES-1, at 27-28; NG-MES-8; NG-MES-9; NG-MDL-2-Boston Gas (Rev. 3), at 20; NG-MDL-2-Colonial Gas (Rev. 3) at 20; NG-MDL-6-Boston Gas WP 2; NG-MDL-8-Colonial Gas, WP 2; AG-1-51; AG-1-52; AG-2-51).

In addition, the Department finds that National Grid has taken reasonable and effective measures to contain its health care costs (see, e.g., Exhs. AG-1-52; AG-15-28; AG-15-33). For example, National Grid has moved to a self-insurance platform; all non-union medical and dental plans are now self-insured while certain union employees are now covered by a self-insurance plan (Exh. AG-1-52). National Grid has also brought all non-union employees under a common benefit platform to reduce the number of medical and dental vendors, which has stabilized and reduced administrative expenses through economies of scale (Exh. AG-1-52). National Grid also provides access to health and wellness programs designed to reduce health care risks, reduce the occurrence of costly diseases, and improve employees' health status (Exh. AG-1-52).

Having found that National Grid has demonstrated: (1) its health care expenses for the test year are reasonable; (2) its proposed post-test year adjustments to remove expenses related to strike contingency and CWIP are known and measurable; and (3) it has taken appropriate measures to contain health care costs, we accept National Grid's proposed reductions to its test year costs of service of $1,195,351 for Boston Gas-Essex Gas and $564,049 for Colonial Gas.

B. Computer Software

1. Introduction

During the test year, customer software expense originally was booked as follows: (1) $2,421,547 to Boston Gas-Essex Gas; and (2) $550,896 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7). National Grid reduced the test year amount for Boston Gas-Essex Gas by $252,496 and reduced the test year amount for Colonial Gas by $62,495 to account for software impairment (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7).[185]

National Grid proposes post-test year adjustments that increase the cost of service of Boston Gas-Essex Gas by $40,995 and increase the cost of service of Colonial Gas by $9,230 to account for what it contends are known and measurable expenses related to information technology projects that are underway and will be completed before the midpoint of the rate

185 National Grid contends that this adjustment is necessary to account for the fact that certain software licenses were purchased but will not be used (Exhs. DPU-11-3; DPU-11-4; NG-MDL-6-Boston Gas WP 3, at 2; NG-MDL-8-Colonial Gas WP 3, at 2).

year (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7, 21; NG-MDL-2-Colonial Gas (Rev. 3) at 7, 21; NG-MDL-1, at 24, 67).[186] The expenses include (1) the costs of specific license and maintenance fees as well as the amortization of capitalized software costs;[187] (2) system-related costs associated with the consolidation of call center operations in Northborough, Massachusetts; and (3) software and hardware upgrades related to improved operational processes to reduce service interruptions and outage time (Exh. NG-MDL-1, at 24-25). No party commented on the proposed adjustments.

2. Analysis and Findings

With respect to computer software expense, the Department typically includes a test year level of expenses in cost of service and will adjust this level only for known and measureable changes to the test year. D.P.U. 0-71, at 120; D.P.U. 87-260, 75. The Department finds that National Grid has properly removed from the test year, expenses associated with computer software for which licenses were purchased but will not be used

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186 National Grid initially proposed to increase the test year computer software expense of Boston Gas-Essex Gas by $553,628 and to increase the test year computer software expense of Colonial Gas by $102,280 (Exhs. NG-MDL-2-Boston Gas at 7; NG-MDL-2-Colonial Gas at 7). During the course of the proceeding, National Grid identified several software projects that were internally approved but not yet undertaken (Exhs. NG-MDL-2-Boston Gas (Rev. 1) at 21; NG-MDL-2-Colonial Gas (Rev. 1) at 21; NG-MDL-6-Boston Gas WP 3, at 1; NG-MDL-8-Colonial Gas WP 3, at 1; AG-12-10). Consequently, National Grid removed $512,633 from its original proposed computer software expense adjustment for Boston Gas-Essex Gas and $93,050 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 1) at 21; NG-MDL-2-Colonial Gas (Rev. 1) at 21).

187 National Grid states that the majority of these projects are related to providing additional online services for customers and improving overall customer service operations (Exh. NG-MDL-1, at 24).

because of economic conditions and constraints on capital priorities (Exhs. DPU-11-3; DPU-11-4; NG-MDL-6-Boston Gas WP 3, at 2; NG-MDL-8-Colonial Gas WP 3, at 2). Further, the Department finds that National Grid properly removed expenses that were attributable to software projects that were internally approved, but not yet committed to by management (Exhs. NG-MDL-2-Boston Gas (Rev. 1) at 21; NG-MDL-2-Colonial Gas (Rev. 1) at 21; NG-MDL-6-Boston Gas WP 3, at 1; NG-MDL-8-Colonial WP 3, at 1; AG-12-10). As these projects remain uncompleted and uncommitted, the expenses cannot be considered known and measurable.

Finally, National Grid proposes to increase the test year costs of service by $40,995 for Boston Gas-Essex Gas and by $9,230 for Colonial Gas to account for what it contends are known and measurable expenses related to information technology projects that are currently underway and intended to be completed before the midpoint of the rate year (Exhs. NG-MDL-1, at 24, 67; NG-MDL-2-Boston Gas (Rev. 3) at 7, 21; NG-MDL-2-Colonial Gas (Rev. 3) at 7, 21). National Grid calculates the proposed adjustments by applying an inflation factor equal to 1.89 percent to the revised test year costs associated with these projects (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 21; NG-MDL-2-Colonial Gas (Rev. 3) at 21).[188] However, National Grid has not provided any substantiation for these increases (Exhs. NG-MDL-1, at 24, 67; NG-MDL-2-Boston Gas (Rev. 3) at 21; NG-MDL-2-Colonial Gas (Rev. 3) at 21). The Department finds that the Companies' proposed adjustments are speculative in

188 The 1.89 percent inflation factor is the same factor proposed by the Companies for their proposed facilities consolidation and lease expense and inflation allowance (see Sections X.C and X.M, respectively, below).

nature and, thus, fail to constitute a known and measurable change to test year cost of service. D.P.U. 09-39, at 157; D.P.U. 95-118, at 130-131; D.P.U. 90-121, at 119; D.P.U. 84-25, at 146-148. Therefore, the Department declines to adopt the Companies' proposed inflation-related adjustment for computer expense.

Based on the foregoing analysis, the Department will reduce Boston Gas-Essex Gas' proposed cost of service by $40,995. The proposed cost of service for Colonial Gas will be reduced by $9,230.

C. Facilities Consolidation and Lease Expense

1. Introduction

During the test year, National Grid booked overall facilities expense (direct and allocated)[189] as follows: (1) $5,185,773 to Boston Gas-Essex Gas; and (2) $961,073 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7, 23; NG-MDL-2-Colonial Gas (Rev. 3) at 7, 23). National Grid proposes to increase its cost of service by $1,921,463 for Boston Gas-Essex Gas and $334,605 for Colonial Gas based on an allocation of certain shared facilities, as discussed below (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7, 23; NG-MDL-2-Colonial Gas (Rev. 3) at 7, 23).

National Grid submits that, of the overall facilities expense booked in the test year, Boston Gas-Essex Gas incurred $1,663,230 in direct expenses and Colonial Gas incurred $254,763 in direct expenses (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-

189 The Companies incur facilities costs either as a direct owner or in the form of a rental charge based on an allocation of certain shared facilities (Exh. NG-MDL-1, at 25, 67).

Colonial Gas (Rev. 3) at 23). National Grid proposes no adjustments to these expenses (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23).

The remaining test year expenses and proposed adjustments are based on an allocation of certain shared facilities (Exh. NG-MDL-1, at 25-26, 67-68). According to National Grid, the method used to allocate costs to Boston Gas-Essex Gas and Colonial Gas is identical to the allocation method approved by the Department for Massachusetts Electric Company ("MECo") in D.P.U. 09-39 (Exh. NG-MDL-1, at 26, 68). No party commented on the proposed adjustments. The individual expenses are discussed below.

2. Reservoir Woods Facility

The Reservoir Woods facility in Waltham, Massachusetts, is the principal location for New England-based service company personnel (Exh. NG-MDL-1, at 25, 67-68). The facility costs associated with Reservoir Woods are billed to Boston Gas-Essex Gas and Colonial Gas as a rental charge from NGSC (Exh. NG-MDL-1, at 26, 68). The Reservoir Woods facility rental charge consists of two components: an operating lease component and a charge for leasehold improvements incurred by NGSC (Exh. NG-MDL-1, at 26, 68-69).

In the test year, National Grid booked $619,097 to Boston Gas-Essex Gas and $103,520 to Colonial Gas in operating lease-related expenses for this facility (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23). National Grid proposes to increase costs of service by $233,770 for Boston Gas-Essex Gas and $39,507 for Colonial Gas to recognize the annualized amount of each entity's share of contractual lease costs (Exh.

NG-MDL-1, at 26-27, 69).[190] The proposed adjustments result in a proposed facilities expense for Reservoir Woods of \$852,867 for Boston Gas-Essex Gas and \$143,027 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23).

During the test year, no expenses were booked to Boston Gas-Essex Gas or Colonial Gas for improvements made at the Reservoir Woods facility (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23). National Grid, however, proposes to increase costs of service by \$255,425 for Boston Gas-Essex Gas and \$42,834 for Colonial Gas relating to improvements at this facility to recognize each entity's share of leasehold improvements at Reservoir Woods (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23).

3. Northborough Facility

National Grid's New England customer contact hub is located at a facility in Northborough, Massachusetts, which supports both gas and electric operations (Exh. NG-MDL-1, at 26, 68; Tr. 17, at 2443). The facility is owned by MECo, which bills the cost of the building to NGSC (Tr. 17, at 2448). NGSC then allocates these costs to the associated regulated entities for which the facility provides services, including Boston Gas-Essex Gas and Colonial Gas (Exh. NG-MDL-1 ,at 26, 68; Tr. 17, at 2448-2449). The annual costs for this facility are segregated into existing facilities costs and leasehold improvements (Exh. NG-MDL-1, at 27, 69).

190 National Grid states that occupancy occurred throughout the 2009 test year so the test year books of account do not reflect a full year of lease costs (Exhs. NG-MDL-1, at 26-27, 69; NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial (Rev. 3) at 23; Tr. 6, at 745).

During the test year, National Grid did not book any lease-related expenses associated with this facility to Boston Gas-Essex Gas or Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 747). National Grid, however, proposes to increase costs of service by $760,972 for Boston Gas-Essex Gas and $125,097 for Colonial Gas to recognize each entity's share of facilities costs for the rate year (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 747).

During the test year, there were no expenses booked to Boston Gas-Essex Gas or Colonial Gas for improvements at the Northborough facility (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 747). National Grid, however, proposes to increase costs of service by $1,031,213 for Boston Gas-Essex Gas and $169,868 for Colonial Gas to recognize each utility's share of improvements at this facility during the rate year (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 747).[191]

4. Other Facilities

During the test year, National Grid booked lease expenses related to a facility on Second Avenue in Waltham, Massachusetts as follows: (1) $356,305 to Boston Gas-Essex Gas; and (2) $57,816 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23;

191 In its initial filing, National Grid identified these proposed adjustments as $194,781 for Boston Gas-Essex Gas and $32,724 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas at 23; NG-MDL-2-Colonial Gas at 23). National Grid subsequently revised these amounts after determining that the original figures were erroneously calculated (Exhs. AG-12-13 (Supp.); AG-12-13, Att. (Supp.); Tr. 17, at 2442).

NG-MDL-2-Colonial Gas (Rev. 3) at 23). National Grid states that the Companies are in the process of vacating this facility and, therefore, proposes to remove these expenses from the test year costs of service for Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-MDL-1, at 27, 69; NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 747-748).

During the test year, National Grid also booked lease expenses related to facilities in Beverly, Massachusetts and Malden, Massachusetts to Boston Gas-Essex Gas in the amount of $81,645 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 23). National Grid states that the gas operating activities at these facilities are scheduled to be consolidated with the electric operating facilities in each community but this has not yet occurred (Exh. NG-MDL-1, at 27; Tr. 6, at 740). National Grid proposes to remove these expenses from the test year cost of service for Boston Gas-Essex Gas (Exhs. NG-MDL-1, at 27-28; NG-MDL-2-Boston Gas (Rev. 3) at 23; Tr. 6, at 748).

The remaining residual test year facility expenses represent costs associated with other National Grid facilities for which no discrete plans for consolidation are imminent. Such expenses were booked as follows: (1) $4,128,726 to Boston Gas-Essex Gas; and (2) $799,737 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial (Rev. 3) at 23). National Grid proposes to increase these test year costs by 1.89 percent to account for inflation (Exhs. NG-MDL-1 at 28, 69; NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial (Rev. 3) at 23; Tr. 6, at 748). This results in proposed increases of $78,033 for Boston Gas-Essex Gas and $15,115 for Colonial Gas (Exhs.

NG-MDL-1 at 28, 69; NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23). Thus, the proposed expenses for these remaining facilities are $6,666,373 for Boston Gas-Essex Gas and $1,295,678 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial (Rev. 3) at 23).

5. Analysis and Findings

a. Introduction

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

b. Reservoir Woods Facility

The Companies are presently occupying space at Reservoir Woods and rental facility costs associated with this facility are billed to the Companies as a rental charge from NGSC (Exh. NG-MDL-1 at 26, 67-68; Tr. 6, at 743-745). Therefore, as they are based on billed rental charges, the Department finds that the proposed adjustments to the Reservoir Woods lease expenses are reasonable and represent a known and measurable change to the Companies' test year cost of service (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 743-745). See 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 One) at 153. Accordingly, the Department accepts National Grid's proposed facility expense adjustments for the Reservoir Woods facility.

c. Northborough Facility

The Northborough call center is owned by Massachusetts Electric Company, which bills the costs of the building to NGSC (Exh. NG-MDL-1, at 26, 68; Tr. 6, at 744; Tr. 17, at 2448). NGSC then allocates those costs to the various affiliates that are served by the facility (Tr. 6, at 744; Tr. 17, at 2448-2449). National Grid moved its call center operations to the Northborough facility by June of 2009 (Tr. 17, at 2447). The proposed adjustments are intended to annualize expenses incurred as of January 2010 so that a full year of costs are included in rates (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 17, at 2447). This results in a proposed lease expense of $1,031,213 and $169,868 for Boston Gas-Essex Gas and Colonial Gas, respectively (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; AG-12-13 (Supp)).

The proposed lease expense represents the annualization of costs projected over the period from November of 2010 through October of 2011 (Exhs. AG 12-13, Att. (Supp); NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23). Because the proposed expense relies in part on a carrying charge component that decreases over time, the Department finds that the Companies' proposal is speculative, and thus fails to meet the Department's known and measurable standard. See D.P.U. 95-118, at 42, n.24; D.P.U. 89-114/90-331/91-80 (Phase One) at 153. Moreover, a portion of the lease expense recognizes depreciation expense and a carrying charge rate of 11.48 percent, which represents the pre-tax weighted cost of capital approved for MECo and Nantucket Electric Company ("Nantucket Electric") in D.P.U. 09-39 (Exh. AG-12-13 (Supp.); AG 12-13, Att. (Supp.); Tr. 17, at 2449-2451). The 11.48 percent weighted cost of capital was approved for different companies based on different evidentiary records. Therefore, the Department finds that application of the proposed 11.48 percent weighted cost of capital to determine the Companies' allocated share of the Northborough facility overstates the required lease expense, and would result in the Companies' ratepayers subsidizing the overall operations of MECo and Nantucket Electric. D.P.U. 08-27, at 84.

In order to derive the appropriate lease expense for ratemaking purposes, the Department will annualize the Companies' lease expense based on the total Northborough facility lease payment for October of 2010 and the pre-tax weighted cost of capital being approved in this Order, which produces a monthly lease expense of $341,995 (see Exhs. AG-12-13 (Supp.); AG-12-13, Att. (Supp.). This results in an annualized Northborough facility lease expense of $4,103,940, with Boston Gas-Essex Gas' and Colonial Gas' allocated portions being $1,042,401 and $171,546, respectively. Accordingly, Boston Gas-Essex Gas' proposed cost of service will be increased by $11,118, and Colonial Gas' proposed cost of service will be increased by $1,678, respectively.

d. Other Facilities

The Department has reviewed National Grid's proposed adjustments to remove expenses related to the Second Avenue, Waltham facility and the facilities in Beverly and Malden (NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23).

The Companies are in the process of vacating the Waltham facility and Boston Gas has decided to consolidate its separate gas and electric facilities in Beverly and Malden into the current electric facilities in these communities (Exh. NG-MDL-1, at 27, 69; Tr. 6, at 740, 747). Given that the Companies will not incur expenses related to these facilities in the rate year, the Department finds that they have been properly excluded from the test year costs of services of Boston Gas-Essex Gas and Colonial Gas (Tr. 6, at 740, 747-748). Accordingly, the Department accepts National Grid's facility expense adjustments related to the Second Avenue, Waltham facility and the facilities in Beverly and Malden.

Turning to the remaining National Grid facilities, the Companies have proposed to increase the cost of service relative to these facilities to account for inflation (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial Gas (Rev. 3) at 23; Tr. 6, at 748). National Grid has not provided any substantiation for these increases (Exhs. NG-MDL-1, at 28, 69; NG-MDL-2-Boston Gas (Rev. 3) at 23; NG-MDL-2-Colonial (Rev. 3) at 23). The Department finds that the Companies' proposed inflation adjustments for these facilities are speculative in nature and, thus, are not known and measurable changes to test year cost of service. D.P.U. 09-39, at 157-158; D.P.U. 95-118, at 130-131; D.P.U. 90-121, at 119; D.P.U. 84-25, at 146-148. Therefore, the Department declines to adopt the Companies' proposed adjustments. Accordingly the proposed cost of service for Boston Gas-Essex Gas will be reduced by $78,033 and the proposed cost of service for Colonial Gas will be reduced by $15,115.

D. Uninsured Claims Expense

1. Introduction

Through April 2009, Boston Gas, Essex Gas, and Colonial Gas participated with other National Grid subsidiaries in a "captive" insurance arrangement under which the Companies paid insurance premiums to shift the risk of their self-insured retention amount to a third party (Exh. NG-MDL-1, at 28, 70). National Grid states that the captive arrangement was terminated in 2009, after the program incurred claims well in excess of its premiums (Exh. NG-MDL-1, at 28). Following the termination of the captive arrangement and for the remainder of the test year, National Grid self-insured on behalf of its Massachusetts gas distribution operations for third party general liability claims for personal injury and property damage, medical coverage, dental coverage, and workers' compensation coverage (Exh. AG-1-63, at 1).

Consistent with the coverage limits provided during the period of participation in the captive arrangement, the Companies self-insure the deductible portion of their liability and workers' compensation costs up to \$3.0 million per claim for general liability and auto liability, and up to \$1.0 million per claim for workers compensation liability (Exh. NG-MDL-1, at 29, 70). The Companies also secure excess liability and workers' compensation insurance for amounts above these levels (Exh. NG-MDL-1, at 29, 70).

During the test year, National Grid booked payments associated with self-insurance claims as follows: (1) \$2,645,778 for Boston Gas-Essex Gas, and (2) \$318,823 for Colonial Gas (Exhs. NG-MDL-1, at 29, 71; NG-MDL-2-Boston Gas (Rev. 3) at 7; 24; NG-MDL-2-

Colonial Gas (Rev. 3) at 8, 24). To establish the annual level of uninsured claims expense to be included in the cost of service, National Grid computed a five-year average of deductible expense (Exh. NG-MDL-1, at 29, 70). For Boston Gas-Essex Gas, the five-year average amounts to $4,588,629, to which $127,995 of administrative costs were added, resulting in a pro forma uninsured claims expense of $4,716,624 (Exhs. NG-MDL-1, at 29; NG-MDL-2-Boston Gas (Rev. 3) at 24). For Colonial Gas, the five-year average amounts to $402,637, to which $11,130 of administrative costs were added, resulting in a pro forma uninsured claims expense of $413,767 (Exhs. NG-MDL-1, at 70-71; NG-MDL-2-Colonial Gas (Rev. 3) at 24). Thus, National Grid proposes to increase the test year cost of service of Boston Gas-Essex Gas by $2,070,846 and to increase the test year cost of service of Colonial Gas by $94,944 (Exhs. NG-MDL-1, at 29, 71; NG-MDL-2-Boston Gas (Rev. 3) at 7, 24; NG-MDL-2-Colonial Gas at 7, 24).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that National Grid is proposing to collect an extraordinary amount of self-insurance expense for claims that were the result of the Companies' own negligence (Attorney General Brief at 113; Attorney General Reply Brief at 68). According to the Attorney General, claims made during three of the five years National Grid used to determine the level of uninsured claims expense include significant amounts for claims that resulted from the Companies' negligence and imprudent actions (Attorney General Brief at 113, citing Exhs. AG-1-79 (Confidential); AG-33-21; AG-33-22; AG-33-24; AG-33-25;

AG-33-26; AG-33-27). The costs in question relate to gas incidents, property damage, and personal injury claims (Attorney General Brief at 113). Thus, the Attorney General asserts that the Department should remove these claims from the five-year average in order to remove the effects of these significant payouts (Attorney General Brief at 113; Attorney General Reply Brief at 68-69). According to the Attorney General, the removal of these claims is consistent with the Department's precedent because customers should not be required to pay for the Companies' negligence in its operations and management and the costs associated with the aforementioned claims (Attorney General Reply Brief at 68-69, citing D.P.U. 88-67, at 102; Boston Gas Company, D.P.U. 1100, at 84-86 (1982)).

b. National Grid

National Grid argues that there is no precedent to support the Attorney General's recommendation to remove claims that arose from negligence from the five-year average of self-insurance expenses (National Grid Brief at IX.21; National Grid Reply Brief at 113). Rather, National Grid asserts that the Department has consistently allowed recovery of self-insured damage claims for general liability, workers' compensation, employee liability, auto liability, crime, directors' and officers' liability, and other claims (National Grid Brief at IX.21, citing D.P.U. 09-30, at 219-220; D.P.U. 07-71, at 92-93; D.T.E. 05-27, at 134-135, 137-138; Massachusetts Electric Company, D.P.U. 89-194/195, at 73-75 (1990); National Grid Reply Brief at 113). National Grid argues that all of the uninsured claims referenced by the Attorney General are precisely the types of events that would be covered by insurance policies obtained by the Companies (National Grid Brief at IX.21). Further, National Grid contends that there is no demonstration that the Companies were negligent or otherwise imprudent in any of the cases raised by the Attorney General and, therefore, there is no basis for the Department to disallow these costs (National Grid Reply Brief at 112-113).

National Grid submits that it followed Department ratemaking practice in calculating self-insured expense and the resulting adjustment to the cost of service, including calculating the expense on the basis of a five-year average of actual claims paid (National Grid Brief at IX.21). As such, National Grid asserts that the self-insured expenses are properly includable in rates (National Grid Brief at IX.21-22, citing D.P.U. 09-30, at 219-220; D.P.U. 07-71, at 92-93; D.T.E. 05-27, at 134-135, 137-138; D.P.U. 89-194/195, at 73-75).

3. Analysis and Findings

The Department recognizes that because self-insured damage claims vary from year to year, limiting recovery to test year levels may not produce a representative level of claims expense on a forward-looking basis. See generally D.P.U. 87-59, at 35-40. The critical inquiry in examining uninsured claims expense is not whether the test year amount is extraordinary but whether it is representative. For this reason, the Department has used a five-year average to determine the level of self-insured payments for ratemaking purposes. D.P.U. 89-194/195, at 73-75 (1990).

The record demonstrates that all monetary settlements resulting from claims or lawsuits filed against the Companies during the test year were within the Companies' $3.0 million deductible for automobile and general liability or $1.0 million deductible for workers' compensation and, therefore, the Companies and not their insurers paid these claims (Exh.

AG-1-79 (Rev.) (Confidential)). The Department has reviewed the specific claims that the Attorney General proposes should be removed from the five-year average of self-insured expense (Exhs. AG-33-21; AG-33-22; AG-33-24; AG-33-25; AG-33-26; AG-33-27). These claims were negligence-based and included allegations of property damage and/or personal injuries (Exhs. AG-33-21; AG-33-22; AG-33-24; AG-33-25; AG-33-26; AG-33-27). The Department finds that there is nothing in the record to suggest that these claims are not representative of the types of events that would be covered under a typical liability or workers compensation insurance policy. Accordingly, we will not exclude these claims from the five-year average used to determine the appropriate level of self-insured payments for ratemaking purposes.

We find that National Grid has correctly calculated the proposed adjustment to the Companies' self-insured expenses (Exhs. NG-MDL-1, at 29, 70-71; NG-MDL-2-Boston Gas (Rev. 3) at 24; NG-MDL-2-Colonial Gas (Rev. 3) at 24). Accordingly, the Department accepts National Grid's proposed uninsured expense adjustments.

E. Property and Liability Insurance

1. Introduction

National Grid carries a variety of insurance coverages including general liability, excess liability, property damage, worker's compensation, public liability, directors and officers, professional indemnity, property terrorism, business travel accident, and blanket crime coverage (Exhs. AG-1-61(BOS) Att. at 1; AG-1-61(COL) Att. at 1). Insurance is purchased to cover the risks of all National Grid entities and the premiums are paid by the service companies and allocated to numerous subsidiaries, including the Companies, either directly or based on individual allocation factors that vary by policy type and the nature of the insured perils (Exhs. MG-MDL-1, at 30; NG-MDL-2-Boston Gas (Rev. 3) at 25; NG-MDL-2-Colonial Gas (Rev. 3) at 25; AG-1-61, at 1).[192] Most premium payments are not expensed as incurred but instead are recorded on the Companies' balance sheet as prepaid assets that are amortized over the life of the insurance policy (Exh. AG-1-61, at 1).

During the test year, insurance expense was booked as follows: (1) $973,123 to Boston Gas-Essex Gas; and (2) $207,210 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7). Based on the most recent insurance bills, the annualized cost of insurance premiums to be charged to Boston Gas-Essex Gas is $1,347,811, which amounts to an increase in test year expense of $376,488 (Exhs. NG-MDL-1, at 30; NG-MDL-2-Boston Gas (Rev. 3) at 7, 25). The annualized cost of insurance premiums to be charged to Colonial Gas is $263,736, which amounts to an increase in test year expense of $56,945 (Exhs. NG-MDL-1, at 71; NG-MDL-2-Colonial Gas (Rev. 3) at 7, 25). No party commented on the proposed adjustments.

2. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.P.U. 02-24/25, at 161; D.P.U. 92-250, at 106. The Companies have provided

192 Premiums were allocated to Boston Gas-Essex Gas and Colonial Gas from both NGSC and KeySpan Corporate Services (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 25; NG-MDL-2-Colonial Gas (Rev. 3) at 25).

updated invoices, policy information, and explanations for the increases in various insurance premiums, including worker's compensation, surety bonds, and excess liability (Exhs. AG-1-61, Att.(2); AG 1-61, Att.(3); AG-33-12; AG-33-13; AG-33-14; AG-33-15). As such, we find that National Grid has demonstrated a known and measureable change to test year insurance premiums expenses. See D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106; D.P.U. 86-86, at 10.

The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. See, e.g., D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185. National Grid's prefiled testimony concerning its insurance expenses is limited to representations that its proposed insurance expense is known and measurable on the basis of insurance bills received and did not address what measures it took to control costs (Exh. NG-MDL-1, at 30). Based on a review of the Companies' supporting workpapers, the Department has determined that National Grid engaged the services of insurance brokers for at least some of its insurance needs (Exh. NG-MDL-6 Boston Gas WP at 21-25). Additionally, the Department has determined that the Companies received an allocated share of continuity credits from insurance carriers (Exh. NG-MDL-6 Boston Gas WP at 3, 9). Therefore, we find that the Companies undertook reasonable measures to control property and liability insurance expenses. Moreover, the Department finds that the proposed increases to property and liability insurance are supported by the evidence and, therefore, are known and measurable (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 7, 25, 26; NG-MDL-2 Colonial Gas (Rev. 3) at 7, 25, 26; AG-2-61 (Atts. 2, 3);

AG-33-12; AG-33-14; AG-33-15). Accordingly, the Department accepts National Grid's proposed property and liability expense. We remind all gas and electric companies seeking adjustments to their property and liability insurance expenses of their obligation to demonstrate that they have taken reasonable measures to control such costs. In the future, companies should provide a narrative explanation in their direct filing of the measures they have undertaken to control these expenses.

F. Pension and Post-Retirement Benefits Other Than Pension

1. Introduction

The Department approved a fully reconciling pension and post-retirement other than pension ("PBOP") reconciling mechanism for Boston Gas in its last rate case. See D.T.E. 03-40, at 308-309. As a result, Boston Gas collects its pension and PBOP expense through an annual pension adjustment factor ("PAF") which reconciles the annual costs of pensions and PBOP with a base amount established in the mechanism and allows for recovery of the difference outside of base rates (Exh. NG-MDL-1, at 49). Essex Gas and Colonial Gas currently do not have a pension and PBOP reconciling mechanism (Exh. NG-MDL-1, at 49, 84).

National Grid proposes to extend the application of the current Boston Gas PAF to Essex Gas, consistent with the consolidation of the Boston Gas-Essex Gas entities (Exh. NG-MDL-1, at 49; Tr. 10, at 1305). National Grid also seeks to extend the application of the PAF to Colonial Gas (Exh. NG-MDL-1, at 84; Tr. 10, at 1305).

Boston Gas currently includes in its base rates $6,230,016 in pension expense and $6,021,759 in PBOP expense (Exh. NG-MDL-1, at 51). These base amounts were established using actual expense for Boston Gas for calendar year 2002, which was the test year used for the rate proceeding in D.T.E. 03-40 (Exh. NG-MDL-1, at 51). National Grid proposes to change the base amount of pension and PBOP expense to be recovered through the PAFs to incorporate two elements. First, the base levels would include amounts for Boston Gas-Essex Gas and Colonial Gas. Second, the base levels would include the level of pension and PBOP costs recorded on the books of Boston Gas, Essex Gas, and Colonial Gas using the most recently received actuarial reports, along with the amortization of previously deferred fair market valuations of the pension and PBOP plans pursuant to purchase accounting rules under FAS 87 and FAS 106 as triggered by the National Grid/KeySpan merger (Exh. NG-MDL-1, at 50-51, 84). National Grid proposes to include the revised base levels in the respective PAFs beginning November 1, 2010 (Exh. NG-MDL-1, at 51, 84).

During the test year, National Grid booked pension expense as follows: (1) $10,990,358 for Boston Gas-Essex Gas; and (2) $6,501,990 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 3; NG-MDL-4-Colonial Gas at 2). National Grid reduced test year pension expense by $3,985,288 for Boston Gas-Essex Gas and by $1,004,850 for Colonial Gas to account for the removal of charges related to the Companies' early retirement program and a timing adjustment related to Boston Gas' pension transition obligations (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 3;

NG-MDL-4-Colonial Gas at 2). Thus, the adjusted test year amounts are $7,005,070 for Boston Gas-Essex Gas and $5,497,140 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 3; NG-MDL-4-Colonial Gas at 2).

National Grid proposes further adjustments based on the most recently received actuarial reports, along with the amortization of previously deferred fair market valuations (Exh. NG-MDL-1, at 51, 84). Based on this updated data, National Grid proposes to increase the adjusted test year pension expense of Boston Gas-Essex Gas by $12,777,713, for a rate year adjusted amount of $19,782,783 (Exhs. NG-MDL-1, at 51; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 3; NG-MDL-4-Colonial Gas at 2).[193] National Grid proposes to increase the adjusted test year pension expense of Colonial Gas by $783,229, for a rate year adjusted amount of $6,280,369 (Exhs. NG-MDL-1, at 84; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 3; NG-MDL-4-Colonial Gas at 2).

During the test year, National Grid booked PBOP expense as follows: (1) $8,186,836 to Boston Gas-Essex Gas; and (2) $1,890,470 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 1; NG-MDL-4-Colonial Gas at 1). National Grid reduced test year PBOP expense by $234,306 for Boston Gas-Essex Gas and by $23,688 for Colonial Gas to account for the removal of charges related to the Companies' early retirement program and a timing adjustment related to Boston Gas' PBOP transition obligations (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7;

[193] The proposed rate year amount is $13,552,767 greater than the base level of pension expense included in Boston Gas' current PAF (Exh. NG-MDL-1, at 51).

NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 1; NG-MDL-4-Colonial Gas at 1). Thus, the adjusted test year amounts are $7,952,530 for Boston Gas-Essex Gas and $1,866,782 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 1; NG-MDL-4-Colonial Gas at 1).

National Grid proposes further adjustments based on the most recently received actuarial reports, along with the amortization of previously deferred fair market valuations (Exh. NG-MDL-1, at 51, 84). Based on this updated data, National Grid proposes to increase the adjusted test year PBOP expense of Boston Gas-Essex Gas by $2,047,026, for a rate year adjusted amount of $9,999,556 (Exhs. NG-MDL-1, at 51; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 1).[194] National Grid proposes to increase the adjusted test year PBOP expense of Colonial Gas by $70,561, for a rate year adjusted amount of $1,937,343 (Exhs. NG-MDL-1, at 84; NG-MDL-2-Colonial Gas (Rev. 3) at 7; NG-MDL-4-Colonial Gas at 1).

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

a. <u>Attorney General</u>

The Attorney General states that the Companies collect dollars from their customers to make contributions to their retirement program trust funds which then get invested in stock, bonds, and other investments (Attorney General Brief at 184; Exh. AG-TN-1, at 18). According to the Attorney General, the Companies then make assumptions of the return on

[194] The proposed rate year amount is $3,977,797 greater than the base level of PBOP expense included in Boston Gas' current PAF (Exh. NG-MDL-1, at 51).

those investments which gets credited to the annual pension and PBOP expense accounts (Attorney General Brief at 184; Exh. AG-TN-1, at 18). The Attorney General maintains that although National Grid seeks to earn a return of 11.3 percent on its equity investment, the Companies assume that the return on the equity investments in their pension and PBOP trust fund assets is only 9.0 percent (Attorney General Brief at 184; Exh. AG-TN-1, at 18). Therefore, the Attorney General claims that, in order to not shortchange customers and ensure that the supporting numbers for the PAF calculations are consistent with the numbers used to determine the levels of pension and PBOP expense embedded in base rates, the Department must direct National Grid to assume a return on the equity investments in pension and PBOP trust accounts equal to the Companies' overall rate of return on common equity ("ROE") (Attorney General Brief at 184-185; Exh. AG-TN-1, at 18-19; Tr. 19, at 2794). The Attorney General asserts that in no case should the return on equities in the trust fund be less than the allowed ROE that the Department establishes in this base rate proceeding (Attorney General Brief at 186; Attorney General Reply Brief at 90-91; Exh. AG-TN-1, at 18-19).

b. National Grid

National Grid contends that its pension and PBOP expenses are dependent on the combined impact of stock market performance, interest rates, and financial accounting standards, over which the Companies have no control (Exh. NG-MDL-1, at 50). According to National Grid, these factors combine to cause substantial volatility in the annual expense and, in periods of extreme volatility, have a profound impact on the Companies' cost structures (Exh. NG-MDL-1, at 50). National Grid states that the PAF functions to align the costs that the Companies incur for providing pension and PBOP benefits with the amounts collected in rates with more precision than can be accomplished through recovery in base rates and ensures that customers pay no more and no less than the actual costs incurred by the Companies over time (Exh. NG-MDL-1, at 50).

3. Analysis and Findings

In D.T.E. 03-40, at 308-309, the Department permitted Boston Gas to implement a reconciling mechanism for its pension and PBOP costs. The Department also has approved pension and PBOP adjustment mechanisms for other gas and electric distribution companies. See, e.g., D.P.U. 09-39, at 221-223; D.P.U. 09-30, at 213; D.T.E. 05-27, at 120; Fitchburg Gas and Electric Light Company, D.T.E. 04-48, at 21, 22-24 (2004); NSTAR Pension, D.T.E. 03-47-A at 2-8 (2003). In D.P.U. 07-50-A at 50, the Department placed distribution companies on notice that they would be required to demonstrate that the continued use of reconciling mechanisms is warranted.[195]

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[195] In particular, the Department stated:

> Regarding the continuation of fully reconciling cost recovery mechanisms after decoupling, the Department notes that at the time these mechanisms were approved, we found that the costs to be recovered were volatile and fairly large in magnitude, were neutral to fluctuations in sales volumes, and were beyond the control of the companies. See NSTAR Electric Company and NSTAR Gas Company, D.T.E. 03-47-A, at 25-28, 36-37 (2003); Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005). As circumstances change, the Department will consider which, if any, of these currently reconciled costs should continue to be fully reconciled via a separate mechanism or recovered instead via base rates. Such consideration will take place on a case-by-case basis, in which each distribution company

In establishing the pension reconciling mechanism for Boston Gas in its last rate case, the Department found it was appropriate because of: (1) the magnitude and volatility of pension expense; (2) the role of accounting requirements rather than a company's actions in the pension expense volatility; and (3) the effectiveness of the reconciling mechanism in avoiding the negative effects of the pension expense volatility. D.T.E. 03-40, at 309. These factors continue to be present here (Exhs. NG-MDL-1, at 50; NG-MDL-4-Boston Gas at 3). Accordingly, we find that National Grid has demonstrated that the continuation of Boston Gas' fully reconciling cost recovery mechanism for pension and PBOP costs is warranted. Given the legal consolidation of Boston Gas and Essex Gas and the approval of the consolidation of the rates of these entities in this proceeding, we find it is reasonable to extend the operation of Boston Gas' PAF to Essex Gas. Further, for the same considerations addressed in D.T.E. 03-40, we find that it is appropriate to establish a fully reconciling pension and PBOP cost recovery mechanism for Colonial Gas (Exh. NG-MDL-4-Colonial Gas at 2).

Although National Grid demonstrated that continued application of the PAF was warranted in this case, the Department takes this opportunity to remind all companies that we will continue to explore on a case-by-case basis which, if any, reconciling mechanism currently in place should continue in operation or whether a representative level of the applicable costs should be recovered through base rates. D.P.U. 07-50-A at 50. In all subsequent rate case

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> must demonstrate that continued recovery in a separate mechanism is warranted.

D.P.U. 07-50-A at 50.

filings, a distribution company seeking to retain a current reconciling mechanism or institute a new reconciling mechanism must demonstrate that recovery in a separate mechanism is warranted. D.P.U. 07-50-A at 50; see also D.P.U. 09-39, at 223 n.126; see Section X.X, below.

Turning to the Attorney General's argument that National Grid's return on the equity investments in its pension and PBOP trust funds be tied to the allowed ROE determined in this proceeding, the Department notes that the assumed returns on the equity investments in the Companies' pension and PBOP trust funds represent a long-term expected rate of return on these assets, based on a combination of factors such as investment strategy, asset allocation mix, and the historical performance of equity investments over long periods of time (Exh. AG-1-2(1)(BOS)(6) at 22). In contrast, the ROE used to determine a company's revenue requirement is intended to preserve the Companies' financial integrity, allow them to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603. Thus, there is no basis to support the notion that the two rates, computed differently for different purposes, are somehow interchangeable.

The Department has reviewed National Grid's proposed adjustments to pension and PBOP expense. The Department finds that National Grid properly calculated the pension and PBOP adjustments based on the most recently received actuarial reports, along with the amortization of previously deferred fair market valuations of the pension and pursuant to purchase accounting rules under both FAS 87 and FAS 106, as triggered by the National Grid/KeySpan merger (Exhs. NG-MDL-1, at 50-51; NG-MDL-1, at 84; NG-MDL-2 Boston

Gas (Rev. 3) at 7; NG-MDL-2 Colonial Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 1, 3; NG-MDL-4-Colonial Gas at 1, 2).

Therefore, the Department accepts National Grid's pension expense adjustments, which results in a pension expense for Boston Gas-Essex Gas of $19,782,783, and represents an increase to test year cost of service of $8,792,425. The corresponding pension expense for Colonial Gas is $6,280,369, and represents a decrease of $221,621 to test year cost of service.[196]

Further, the Department accepts National Grid's PBOP expense adjustments, which results in a PBOP expense for Boston Gas-Essex Gas of $9,999,556, and represents an increase to test year cost of service of $1,812,720. The corresponding PBOP expense for Colonial Gas is $1,937,343, and represents an increase to test year cost of service of $46,873.[197]

Finally, the Department accepts the proposed pension and PBOP deferral amortizations for Boston Gas-Essex Gas (Exhs. NG-MDL-2 Boston Gas (Rev. 3) at 7; NG-MDL-4-Boston Gas at 2, 3). This results in a pension deferral amortization of $5,649,745, representing an increase to test year cost of service of $784,837, as well as a PBOP deferral amortization of $1,925,571, representing a decrease to test year cost of service of $1,323,461.

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196 As a result of these adjustments, Boston Gas-Essex Gas' base rates will include $19,782,783 of pension expense and Colonial Gas' base rates will include $6,280,369 of pension expense.

197 As a result of these adjustments, Boston Gas-Essex Gas' base rates will include $999,556 of PBOP expense and Colonial Gas' base rates will include $1,937,343 of PBOP expense.

G. Postage Expense

1. Introduction

During the test year, National Grid booked postage expense as follows: (1) $2,693,426 to Boston Gas-Essex Gas; and (2) $790,047 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 28; NG-MDL-2-Colonial Gas (Rev. 3) at 28). National Grid made a normalizing adjustment of $185,052 to incorporate a refund from the United States Postal Service ("USPS") which was the result of changing postal meters, with $149,823 allocated to Boston Gas-Essex Gas and $35,229 allocated to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 9, 28; NG-MDL-2-Colonial Gas (Rev. 3) at 9, 28). Thus, the revised test year postage expense for Boston Gas-Essex Gas is $2,843,249 and the revised test year postage expense for Colonial Gas is $825,276 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 28; NG-MDL-2-Colonial Gas (Rev. 3) at 28).

National Grid proposes two further adjustments to postage expense totaling $83,800, with $64,947 allocated to Boston Gas-Essex Gas and $18,853 allocated to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 28; NG-MDL-2-Colonial Gas (Rev. 3) at 28). These adjustments as described as follows: First, National Grid proposes to increase test year postage expense by $44,764 ($34,693 allocated to Boston Gas-Essex Gas and $10,071 allocated to Colonial Gas) to incorporate a postage increase that occurred during the test year, on May 11, 2009, for the full twelve months from January 1, 2009, to December 31, 2009 (See Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 28; NG-MDL-2-Colonial Gas (Rev. 3) at 28; NG-MDL-6-Boston Gas WP 8, at 1; DPU-13-4, Att.). Second, National Grid proposes to further increase postage expense by $39,036 ($30,254 allocated to Boston Gas-Essex Gas and $8,782 allocated to Colonial Gas) based on an increase in postal rates the Companies anticipated the USPS would impose effective May 11, 2011 (See Exhs. NG-MDL-1, at 31, 72; NG-MDL-2-Boston Gas (Rev. 3) at 28; NG-MDL-2-Colonial Gas (Rev. 3) at 28; DPU-13-3). No party commented on these proposed adjustments.

2. Analysis and Findings

The Department recognizes postage expense as a legitimate cost of doing business. If a postage rate increase occurs prior to the issuance of an Order, the increase is eligible for inclusion in cost of service as a known and measurable change to test year expense. New England Gas Company, D.P.U. 08-35, at 108 (2009); Bay State Gas Company, D.P.U. 05-27, at 194; Massachusetts American Water Company, D.P.U. 88-172, at 23-24 (1989); Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982).

The postage increase that went into effect during the test year, on May 11, 2009, is known and measurable. New England Gas Company, D.P.U. 08-35, at 108 (2009); Bay State Gas Company, D.P.U. 05-27, at 194. Accordingly, the Department accepts National Grid's proposed normalization adjustment of $44,764 for this increase, with $34,693 allocated to Boston Gas-Essex Gas and $10,071 allocated to Colonial Gas (See Exhs. NG-MDL-6-Boston Gas, WP 8, at 1; DPU-13-4, Att.). With respect to National Grid's proposed adjustment to reflect the anticipated postage increase for 2011, the Postal Regulatory Commission issued a decision denying the USPS request for an exigent rate increase for effect January 2011. Postal Regulatory Commission, Docket No. R2010-R, Order No. 547, Order Denying Request for

Exigent Rate Adjustments (September 30, 2010). Therefore, National Grid's proposed adjustment related to a postage increase in 2011 is not known and measurable and the Department will disallow National Grid's proposed adjustment of $39,036. Accordingly, Boston Gas-Essex Gas' proposed cost of service will be reduced by $30,254 and Colonial Gas' proposed cost of service will be reduced by $8,782.

H. Inside Inspectional Services

1. Introduction

National Grid booked $487,363 in costs for inside inspectional services during the test year ($404,719 for Boston Gas-Essex Gas and $82,644 for Colonial Gas) (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; NG-WJA-3). National Grid proposes to cover the costs of additional mandated inspections by increasing test year inside inspection expense by $778,000, allocating $748,000 to Boston Gas-Essex Gas and $30,000 to Colonial Gas (Exhs. NG-WJA-3; NG-MDL-2-Boston Gas (Rev. 2) at 7; NG-MDL-2-Colonial (Rev. 2) at 7; RR-DPU-14(D)).

The additional inspections were mandated by the Department pursuant to a Consent Order entered into between Boston Gas and the Department's Pipeline Division on February 11, 2008. This Consent Order was the result of an investigation by the Pipeline Division pursuant to G.L. c. 164, § 105A into a gas explosion in Lexington, Massachusetts, D.P.U. 05-PL-17.[198]

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[198] Pursuant to 220 C.M.R. § 1.10(3), the Department incorporates by reference the following documents from D.P.U. 05-PL-17: (1) Notice of Probable Violation, dated

The Consent Order provides that within thirty-six months of the effective date of this Order, Boston Gas shall complete corrosion surveys of all service line segments inside of buildings consistent with the requirements of 49 C.F.R. Part 192, § 192.481.[199] Boston Gas must complete corrosion monitoring inspections of all inside service segments in buildings located within each business district within three calendar years (Consent Order, Compliance Agreement at ¶ 7).[200]

2. National Grid Proposal

National Grid indicates that in order to complete the three-year inspection cycle for the inside meters and services of all of its customers as required by the Consent Order, it will have to complete a total of approximately 611,705 inspections (Tr. 4, at 306-307). Thus, National Grid proposes to conduct one-third of the total required inspections in each year, beginning in 2011 (Exh. NG-WJA-3; Tr. 4, at 306).[201] National Grid proposes to perform 203,905

August 24, 2007 ("NOPV"); (2) Informal Conference Decision, dated January 18, 2008; and (3) Consent Order, dated February 11, 2008.

199 Specifically, the Pipeline Division cited 49 C.F.R. § 192.481 and the requirement to inspect inside gas pipes for evidence of atmospheric corrosion at least once every three calendar years (NOPV at 4).

200 Although Essex Gas and Colonial Gas were not signatories to the Consent Order, National Grid states that these entities began performing inside service inspections concurrently with Boston Gas and consistent with the terms of Consent Order (Tr. 4, at 444-445).

201 National Grid expects to perform 248,141 inspections in 2010, at an annual cost of $1,496,392 (Exh. NG-WJA-3). It does not, however, seek to incorporate these amounts into its proposed adjustment to test year inside inspection costs.

inspections each year in 2011, 2012, and 2013 (Exh. NG-WJA-3; Tr. 4, at 306; RR-DPU-14(D)).

As noted above, National Grid proposes to increase test year inside inspection expense by $778,000, allocating $748,000 to Boston Gas-Essex Gas and $30,000 to Colonial Gas (Exhs. NG-WJA-3; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; RR-DPU-14(D)). Thus, the Companies' proposed annual cost for each inspection cycle is $1,265,480, with $1,152,719 allocated to Boston Gas-Essex Gas and $112,644 allocated to Colonial Gas (Exhs. NG-WJA-3; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; RR-DPU-14(D)).[202]

National Grid indicates that 142,734 total inside inspections were completed in the test year by Boston Gas, Essex Gas, and Colonial Gas (See Exhs. NG-WJA-1, at 18; NG-WJA-3). Of this amount, 109,124 inspections were performed by outside contractors at a cost of $487,363 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; NG-WJA-3). Of this expense, $404,719 was allocated to Boston Gas-Essex Gas and $82,644 was allocated to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7).

National Grid proposes primarily to use outside contractors for the inside service inspections, although internal employees may be called upon to perform follow-up inspections if initial efforts by contractors to access a premises are unsuccessful (Tr. 4, at 450). National Grid states that, where applicable, the outside contractors will perform inside service

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202 Thus, National Grid assigns a cost of approximately $6.21 to each future inspection (Exh. NG-WJA-3; RR-DPU-14(D); Tr. 16, at 2207).

inspections in conjunction with its three-year leak survey program which focuses on inspecting pipe for gas leaks (Exh. NG-WJA-2, at 1; Tr. 4, at 313).

The annual cost of the inside service inspection that National Grid seeks to include in rates, $1,265,480, takes into account contractual arrangement with outside contractors, the projected rate of successful access to the premises, and the need to use internal employees for follow-up inspections (RR-DPU-14; Tr. 4, at 448-450).

3. Positions of the Parties

a. Attorney General

The Attorney General acknowledges that the Companies are obligated to perform the required inside inspections on a three-year cycle in order to maintain a safe and reliable distribution system but she notes that the inspections must nonetheless be done in an economic and efficient manner (Attorney General Brief at 111). According to the Attorney General, the Companies' proposal fails in this regard because it requires that all work will be done by outside vendors rather than internal employees, without demonstrating that use of outside vendors is less expensive (Attorney General Brief at 111). The Attorney General claims that the Companies fail to recognize that their employees are already deployed to do inside inspections on one-seventh of its system each year, when those employees pull meters for routine inspections (Attorney General Brief at 111). Thus, the Attorney General concludes that performing the inside inspections together with the meter replacement inspections would take care of almost one-half of the inside inspections that are required each year (Attorney General Brief at 111). The Attorney General asserts that the Companies fail to explain the logic of requiring customers to pay for separate inside service inspections that could be readily conducted in conjunction with meter change-outs (Attorney General Reply Brief at 69). Further, the Attorney General argues that the Companies failed to provide any support or reasoning for the proposed increase in outside vendor inspection costs from $4.47 per inspection during the test year to the $6.21 that they propose to include in the pro forma cost of service (Attorney General Brief at 111-112; Attorney General Reply Brief at 69).

Based on the above arguments, the Attorney General maintains that the Companies' proposed adjustment for inside service inspections is inflated in the volume of annual inspections required and the overall cost of each inspection (Attorney General Reply Brief at 69-70). Thus, the Attorney General argues that the Companies have failed to demonstrate that the proposed adjustment to test year inside service inspection expenses is known and measurable, or that the proposed costs are least-cost, reasonable, appropriate or prudently incurred (Attorney General Brief at 112; Attorney General Reply Brief at 69-70). The Attorney General asserts that, accordingly, the Department should reject the proposed pro forma adjustment to test year expense (Attorney General Brief at 112; Attorney General Reply Brief at 70).

b. National Grid

National Grid argues that, contrary to the Attorney General's claims, it did consider the cost of using internal employees to perform inside service inspections but determined it was less expensive to hire outside contractors for this purpose (National Grid Brief at IX.17, citing Exh. NG-WJA-2, at 1; RR-DPU-12). More specifically, National Grid contends that, because the outside contractors perform inside service inspections in conjunction with a required three-year walking survey to inspect for pipe leaks, the combined inspections are efficient and will save approximately $765,000 annually (National Grid Brief at IX.17-18, citing Exhs. NG-WJA-2, at 1; DPU-1-3, at 2; Tr. 4, at 400). Conversely, National Grid claims its internal employees cannot perform the inside service inspections more cheaply than outside contractors (National Grid Brief at IX.18). National Grid notes that using internal employees in conjunction with the seven-year meter change-out program as suggested by the Attorney General would only capture a small portion of the overall inside inspections it needs to perform each year (National Grid Brief at IX.18, citing Tr. 4, at 315). In addition, National Grid asserts that an outside contractor will bill on a per-unit basis only for inspections in which the contractor actually gains access to the structure (National Grid Brief at IX.18, citing RR-DPU-14). To the extent that the outside contractor does not gain access to the premises and perform an inspection, National Grid states that no outside vendor cost is incurred. However, a cost would be incurred for an internal employee whether or not an inspection is completed (National Grid Brief at IX.18, citing RR-DPU-14, Att. D; Tr. 4, at 450-451).

Finally, National Grid argues that it has correctly calculated the cost adjustment that is needed to establish the annual cost of inside inspections in rates (National Grid Brief at IX.18). Specifically, National Grid contends that it is necessary to include the cost of the incremental inspections beyond those performed during the test year that are needed to complete one-third of the inspections required during 2010 and beyond (National Grid Brief at IX.18). As a result, National Grid asserts that its proposed adjustment is known and measurable, correctly calculated, and required to implement an important safety procedure mandated by the Department.

4. Analysis and Findings

The Department's long-standing precedent allows only known and measurable changes to test-year expenses to be included in a company's cost of service. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 61-62 (1998) citing Dedham Water Company, D.P.U. 84-32, at 17 (1984). Further, the Department permits a company to reflect expenses in its cost of service if a company can demonstrate that the expense is either annually or periodically recurring or, if non-recurring, is extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. D.P.U. 1270/1414, at 33; see also D.P.U. 89-114/90-331/91-80 (Phase One) at 152; D.P.U. 88-250, at 65-67.

Thus, in order to find that the costs of the inside service inspection program are known and measurable, the Department must find that the adjustments have actually taken place or that record evidence demonstrates that the adjustment will take place. The amount of the adjustment must also be quantifiable.

National Grid commenced the inside service inspection program in 2008 (Exh. NG-WJA-1, at 18; RR-DPU-12).[203] During the test year, outside contractors performed 109,124 inside service inspections at a cost of $487,363 (Exhs. NG-MDL-2-Boston Gas (Rev.

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[203] National Grid does not have a record of the number of inspections completed in 2008 or the costs incurred in performing such inspections (Exh. NG-WJA-1, at 18; RR-DPU-12).

3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; NG-WJ-3). National Grid, however, seeks to adjust test year costs to account for the fact that a full one-third cycle of inspection was not completed during the test year. Beginning in 2011, National Grid intends to assign 203,905 inspections to outside contractors annually, which equals one-third of eligible customers with inside facilities (Exh. NG-WJA-3; Tr. 4, at 306).[204] Thus, National Grid expects to annually assign to contractors an additional 94,781 inspections above the number assigned in the test year. These additional inspections are allocated as 90,510 to Boston Gas-Essex Gas and 4,271 assigned to Colonial Gas (Exhs. NG-WJA-3; RR-DPU-14(D) at 1).

National Grid states that the additional inspections will cost $778,000, which represents the costs to perform inspections beginning in 2011, less test year costs (Exhs. NG-WJA-3; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; RR-DPU-14(D)). Thus, embedded in National Grid's proposal, the cost to perform each inside service inspection has increased from $4.47 in the test year to approximately $6.21 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial (Rev. 3) at 7; NG-WJA-3; RR-DPU-14(D); Tr. 16, at 2207).[205]

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204 We note that, beginning in 2011, the number of annual inside service inspections for Essex Gas customers is expected to decrease by 250 from the test year number (Exh. NG-WJA-3; RR-DPU-14(D)).

205 National Grid states that the higher cost associated with inside inspections takes into account existing contractual arrangements with contractors. It also is based on a number of assumptions concerning the rate of successful access to the premises and the use of internal employees for inspections in some of National Grid's service areas (Exh. AG-40-12; RR-DPU-14(D); Tr. 4, at 448-450). For example, National Grid assumes that only 50 percent of all initial inspections attempted by outside contractors, absent an appointment with the customer, will be completed (Exh. AG-40-12). Further, in some

As an initial matter, the Department finds that National Grid's proposal to use outside contractors to perform inside service inspections is reasonable, particularly because the outside contractors are paid only when an actual inspection takes place and the contractors will coordinate inside service inspections with the walking survey to monitor leaks (RR-DPU-14; Tr. 4, at 313). The Attorney General argues that National Grid employees could perform a percentage of the inside service inspections in conjunction with meter inspections, thereby further reducing the number of inside service inspections performed by contractors (Attorney General Brief at 111; Attorney General Reply Brief at 69). The meter inspections, however, are required once every seven years (see G.L. c.164, § 115A) while inside service inspections will coincide with the three-year cycle for walking surveys to monitor leaks (Exh. NG-WJA-2, at 1; RR-DPU-14(A); RR-DPU-14(B); RR-DPU-14 (Supp.)).

The Department finds that, while the use of outside contractors to perform inside service inspections is reasonable, National Grid has not adequately supported the proposed increase in costs to perform each inside inspection. National Grid based its proposed increase in cost-per-inspection, in part, on the inspection-related contracts currently in place and set to expire at the end of March 2011 (RR-DPU-14(A) at 4; RR-DPU-14(B) at 4). There are no additional contracts in the record that will commence prior to the three-year inspection cycle beginning in 2011. Thus, there is no assurance that the current inspection rates will remain in

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areas of National Grid's service territories, all appointment inspections and/or follow-up inspections will be performed by internal employees and not outside contractors (Exh. AG-40-12; Tr. 4, at 450).

effect for the duration of the three-year inspection cycle and, therefore, we find that the proposed increase in per-inspection costs is not known and measurable. Further, the proposed increase in per-inspection costs is based on several projections and estimates (see, e.g., Exh. AG-40-12; RR-DPU-14(D) at 2-3, providing "estimated" and "projected" contractor costs). Proposed adjustments to test year costs based on projections or estimates are not permitted. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 62 (1998), citing The Berkshire Gas Company, D.P.U. 92-210, at 83 (1993); Dedham Water Company, D.P.U. 849, at 32-34 (1982).

Nevertheless, the Department recognizes that costs related to inside service inspections will be recurring in nature. As such, the Department finds that it is necessary to establish a representative level of costs to apply to the inside service inspections. In order to arrive at an appropriate adjustment, the Department concludes that it is appropriate to maintain the test year per-inspection rate of $4.47 and apply that rate to the incremental number of inspections expected to be conducted by outside contractors beginning in 2011.[206] This level of recovery incorporates the known and measurable per-inspection cost incurred during the test year applied to the additional number of inspections that are expected to begin in 2011. Thus, the Department finds that inside service inspection expense should be increased by $423,670 (94,781 additional inside inspections at $4.47 per inspection), allocated as $404,579 for Boston

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206 Although the number of outside contractor inspections proposed by National Grid for 2011 through 2013 is a projection, it is not impermissibly speculative as it based on a quantifiable number of eligible customers with inside facilities (Exh. NG-WJA-3; Tr. 4, at 306).

Gas-Essex Gas and $19,091 for Colonial Gas. Accordingly, the Department will decrease Boston Gas-Essex Gas' proposed cost of service by $343,421 and decrease Colonial Gas' proposed cost of service by $10,909.

I. Water Main Break Expense

1. Introduction

Early on the morning of April 26, 2008, Boston Gas received a request to locate and mark its facilities in preparation for repairs to what was initially identified as a water service break at the intersection of State Street and Devonshire Street in Boston, Massachusetts (Exhs. DPU-5-18; DPU-17-17; DPU-17-19). When National Grid crews arrived at the location, they observed a significant water leak in progress and called for additional support (Exh. DPU-5-18).[207] National Grid had personnel at the site for the following six days (Exh. DPU-5-18).

As a result of the main break, there was significant street and infrastructure damage in that area, including damage to Boston Gas' distribution system (Exhs. NG-MDL-1, at 32; DPU-17-17). In addition, Boston Gas incurred other costs associated with reimbursing customers for damage to their appliances as a result of water infiltration (Exhs. NG-MDL-1, at 32; DPU 5-18).

Immediately following the water main break, National Grid had multiple discussions with the Boston Water and Sewer Commission ("BWSC") regarding responsibility for the emergency response, remediation, and repair costs associated with the event

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[207] It was later determined that a twelve-inch water main on Devonshire Street had broken sometime early that morning (Exhs. DPU-5-18; DPU-17-17).

(Exhs. NG-MDL-1, at 32; DPU-5-21; DPU-17-15). BWSC denied liability and also asserted that any potential legal action from National Grid would be limited by the Massachusetts Tort Claims Act, which caps recovery from a public employer to $100,000 (Exhs. DPU-5-20, citing G.L. c. 258, § 1; DPU-5-21). In May 2008, National Grid consulted with outside legal counsel concerning its alternatives for legal recourse (Exhs. DPU-5-21; DPU-17-16; Tr. 8, at 1039). Outside counsel advised National Grid that it would require substantial effort to overcome the liability cap and that the costs to do so very likely would exceed the costs incurred in responding to the water main break (Exhs. DPU-5-21; DPU-17-16).[208] Based on this advice, National Grid concluded that further discussions with BWSC in an attempt to recover costs from the City of Boston would be futile (Exh. DPU-5-21).

National Grid states that the water main break caused Boston Gas to incur $2,700,910 in costs in 2008, which it deferred on its books through December 31, 2008, pending the outcome of its efforts to recover costs from the City of Boston (Exhs. NG-MDL-1, at 14, 32; DPU-17-21; Tr. 8, at 1039). National Grid did not request or obtain the Department's approval to defer costs associated with the water main break (Exh. DPU-5-24).

The aforementioned costs were removed from Boston Gas' cost of service in this proceeding but National Grid seeks to amortize over a three-year period incremental costs

[208] National Grid has no record of the date it received such advice from counsel (Exh. DPU-17-16). According to the Companies, all communications with their counsel were conducted over the telephone (Exh. DPU-17-16).

totaling $2,074,841[209] incurred in 2008 that were related to the water main break (Exhs. NG-MDL-1, at 14, 33; DPU-5-25).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Department should deny recovery of the water main break costs because the expenses, incurred in 2008, are pre-test year costs (Attorney General Brief at 107, 108, citing Exh. NG-MGL-1, at 32). The Attorney General asserts that, unless they have received Department approval to defer the costs, utilities may not include in the pro forma cost of service those expenses incurred prior to the test year (Attorney General Brief at 107). Otherwise, she argues, a utility could defer costs during a period when it is earning more than its cost of capital and collect those costs in a future rate case (Attorney General Brief at 107, citing Oxford Water Company, D.P.U. 88-171, at 29-30 (1989); Commonwealth Electric Company, D.P.U. 88-135/151, at 28-29 (1989)).

The Attorney General contends that these costs should be disallowed because National Grid did not receive Department permission to defer the costs (Attorney General Brief at 108-109). Further, the Attorney General disputes National Grid's argument that costs were automatically deferred pending outcome of its efforts to recover them from the City of Boston (Attorney General Brief at 108 n.36). The Attorney General argues that these costs should have been expensed when they were incurred in 2008, rather than in 2009 (Attorney General

209 National Grid initially proposed to amortize $2,230,173 in what it identified as incremental costs but later reduced the proposed amount to be amortized by $155,332 after identifying an error in advertising expenses that was included in the total costs (Exh. NG-MDL-1, at 33; NG-MDL-2-Boston Gas at 30; DPU-5-25; Tr. 8, at 1041).

Brief at 108, citing USOA-Gas, General Accounting Instruction 9 - Accounting Period; Account 887 - Maintenance of Mains). According to the Attorney General, if any costs subsequently were recovered from the City of Boston, that amount could have been credited to O&M expense at the time it was realized (Attorney General Brief at 108 n.36, citing Exh. NG-MDL-1, at 32-33). Finally, the Attorney General argues that, even if the water main break costs are somehow construed as part of the test year O&M expenses, they are nonrecurring, non-extraordinary costs that must be removed from the cost of service (Attorney General Brief at 109, citing Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983)).

b. National Grid

National Grid acknowledges that the water main break costs were incurred prior to the test year and that it did not seek Department approval of a deferral (National Grid Brief at IX.13, 14 citing Exh. NG-MDL-1). National Grid argues, however, that the Department has allowed utilities to recover significant costs beyond their control incurred prior to the test year (National Grid Brief at IX.14). National Grid submits that its request to amortize the \$2,074,841[210] of incremental water main break costs over three years is made in recognition that the costs were both significant and beyond its control (National Grid Brief at IX.14). Additionally, National Grid argues that it periodically incurs costs associated with emergency

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210 In its brief, National Grid proposes to amortize \$2,230,173 in water main break costs over three years (National Grid Brief at IX.13). As noted above, however, \$155,332 in advertising expenses was erroneously included in the above amount. As such, the amount National Grid seeks to amortize should be \$2,074,841 (Exhs. DPU-5-25; NG-MDL-2-Boston Gas (Rev. 3) at 30).

events and, without carrying charges, it is effectively contributing to the cost of emergency response (National Grid Brief at IX.13, citing Exh. NG-MDL-1, at 33). Finally, National Grid claims that the water main break costs are not of the magnitude that require a petition for deferral from the Department, even though the costs are sufficiently significant to merit recovery (National Grid Brief at IX.14).

3. Analysis and Findings

Utilities may not recover through rates any expenses that were incurred prior to the test year. Otherwise, a company making adequate earnings during a particular year could "bank" its expenses to a deferred account and collect them in a future rate case. Commonwealth Electric Company, D.P.U. 88-135/151, at 28-29; see also Oxford Water Company, D.P.U. 88-171, at 29-30 (1989). A company may, however, petition the Department to allow it to defer accounting treatment of expenses incurred prior to the test year. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 09-61 (2009); Aquarion Water Company of Massachusetts, D.P.U. 04-77, at 5 (2004); North Attleboro Gas Company, D.P.U. 93-229 (1994). If certain conditions are met, the Department may allow a company to defer accounting treatment of expenses incurred prior to the test year and will consider the subsequent ratemaking treatment of those expenses in the company's next rate case. Aquarion Water Company of Massachusetts, D.P.U. 04-77, at 5 (2004); citing D.P.U. 93-229, at 7-8.[211]

[211] The Department formulated its current standard for reviewing requests for deferral accounting treatment in D.P.U. 93-229. A utility seeking deferral treatment must demonstrate prima facie in its petition that: (1) based on Department precedent, the annual expense may be recoverable as an extraordinary expense if incurred during a test year; (2) a Department denial of the request for deferral would significantly harm the

In the instant case, Boston Gas incurred the water main break costs in 2008, outside the 2009 test year. National Grid seeks to amortize these pre-test year costs and recover them over a three-year period, arguing that the expenses are significant and outside of its control. Alternately, the Attorney General contends that the Companies' request to recover the water main break costs should be denied as the costs at issue were incurred prior to the test year.

If the costs at issue had occurred in the test year, they would be considered non-recurring costs[212] which, by definition, are not representative of the future levels of costs needed to provide service and are, thus, normally excluded from cost of service.[213] Oxford Water Company, D.P.U. 88-171, at 29 (1989); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983). However, when a non-recurring expense occurs in the test

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overall financial condition of the company; and (3) the Department's denial of the request for deferral is likely to cause the filing of a rate case that would include in its test year the expense for which deferral is sought. D.P.U. 93-229, at 7. Once a prima facie showing is made, the Department will evaluate the petition, considering such additional factors as: (1) the company's ability to choose a test year; (2) the company's history and frequency of rate increases; (3) the company's frequency of requests for deferral; (4) the company's earnings in the year the subject expense was incurred; and (5) whether some voluntary agreement on the part of the petitioner (e.g., a settlement) would otherwise preclude bringing a G.L. c. 164, § 94 petition during the period for which deferral is sought. D.P.U. 93-229, at 7-8.

[212] Although water main breaks do occur with some frequency (see, e.g., Aquarion Water Company of Massachusetts, D.P.U. 09-48), there is no evidence that water main breaks that result in damage to a gas distribution infrastructure are recurring events or that expenses of this type are typical of gas distribution operations.

[213] Alternately, periodically recurring expenses that occur in the test year are included in the cost of service because they are deemed to be representative of costs that rates are designed to collect in the future. Nantucket Electric Company, D.P.U. 88-161/168, at 61-62 (1989); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 16-17 (1983); see, also, Oxford Water Company, D.P.U. 88-171, at 29 (1989).

year and is extraordinary in amount, the Department allows the associated costs to be amortized over an appropriate period. Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983).

The Companies' argument that the Department has previously approved the recovery of significant pre-test year expenses is without basis.[214] While the Department has approved the amortization of non-recurring costs found to be extraordinary in amount, the underlying expenses in those cases either were: (1) incurred during the test year; or (2) if the expenses had occurred prior to the test year, the company had obtained Department approval to defer the costs for consideration in a subsequent rate case. See e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 97-100 (2009) (pension and post retirement expense, security expense, and water contamination incident expense deferrals); Nantucket Electric Company, D.P.U. 91-106/138, at 30-33 (1991) (conservation and load management cost deferrals) Nantucket Electric Company, D.P.U. 88-161/168, at 110-111 (1989) (lease documentation fee); Boston Gas Company, D.P.U. 1100, at 89-92 (1982) (LNG tank repairs); Boston Edison Company, D.P.U. 19991, at 36 (1979). As National Grid acknowledges, Boston Gas' expenses associated with the water main break were incurred before the 2009 test year and no request to defer such expenses was made (Exhs. NG-MDL-1, at 14, 32; DPU-5-24; DPU-5-25(B)).

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214 National Grid cites no support for its contention that there are many examples in which the Department has allowed companies to recover significant costs beyond a company's control (see National Grid Brief at IX.14).

With respect to the issue of a deferral, National Grid argues that the water main break costs were not of a magnitude that warranted a petition for deferral accounting treatment but nonetheless it seeks to amortize these expenses on the basis that the expenses are significant (National Grid Brief at IX.14). Further, National Grid suggests that there was no need to request Department authority to defer the costs because the costs at issue were automatically deferred pending the Companies' negotiations with the City of Boston regarding liability for the event (Exh. DPU-17-22). Neither argument is correct. If a company seeks to have pre-test year costs of any magnitude considered for recovery in a subsequent rate case, it must file a petition with the Department seeking authority to defer such cost. D.P.U. 93-229, at 7-8; Commonwealth Electric Company, D.P.U. 88-135/151, at 28-29 (1989). Deferral is not automatic. As noted above, the purpose of Department approval of a deferral request is to avoid the situation where a utility with adequate earnings could "bank" various expenses through deferral accounting and collect them in a future rate case. In such a case, because previous rates were adequate to absorb the expense, future rate relief based on those expenses would be inappropriate. See D.P.U. 88-135/151, at 29 (1989).

Even had National Grid filed an appropriate request with the Department to defer these costs, we find that the Companies would not have met our standard for deferral. D.P.U. 93-229. Given the size and revenues of Boston Gas, we find the water main costs were not of an extraordinary amount. Thus, these costs should have been booked to expense during 2008, after which, to the extent that Boston Gas may have been successful in its discussions with the

BWSC, any reimbursements could have been booked as an offset against operating expenses during 2009 or thereafter.

And, even if the Department were to find that the water main break costs were extraordinary in amount, the fact remains that these costs were incurred before the test year. As noted above, expenses related to the water main break were incurred prior to the 2009 test year and Boston Gas neither sought nor obtained Department approval to defer such costs for consideration in this rate case. This factor alone renders the water main break costs ineligible for rate recovery. Oxford Water Company, D.P.U. 88-171, at 29-30 (1989); D.P.U. 88-135/151, at 28-29.

Accordingly, for the reasons discussed above and as a matter of sound ratemaking policy, the Department denies National Grid's proposal to amortize for ratemaking purposes the costs related to the 2008 water main break. Therefore, Boston Gas' proposed cost of service will be reduced by $691,613.

J. Strike Contingency

1. Introduction

During the test year, National Grid was engaged in contract negotiations with its largest gas unions (Exh. NG-MDL-1, at 34). As a result, Boston Gas-Essex Gas and Colonial Gas incurred $1,518,163 and $107,246, respectively in costs related to strike contingency preparations in the test year (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8;

NG-MDL-2-Colonial Gas (Rev. 3) at 47).[215] National Grid states that such costs included: (1) hiring of outside contractors to train non-union staff on the use of critical equipment necessary to ensure the continuation of safe operations; (2) initiation of a customer communication program; and (3) implementation of security measures (e.g., changing locks to secure the Companies' assets, fencing installation, purchase of communications equipment, and hiring security personnel) (Exh. NG-MDL-1, at 34).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should disallow the recovery of $376,672 in strike contingency costs (Attorney General Brief at 109-110). The Attorney General argues that these costs do not qualify as strike contingency costs because they either were not required to prepare for a strike or were not incremental costs to National Grid (Attorney General Brief at 109). Specifically, the Attorney General asserts that employee labor-related costs of $312,472 were inappropriately included because National Grid was not required to hire new employees for its strike contingency activities and, thus, these costs were not truly incremental (Attorney General Brief at 109-110, citing Exh. NG-MDL-2-Boston Gas at 31). The Attorney General also contends that the Department should disallow vehicle lease costs of $64,200 because National Grid had in its inventory "hundreds, if not thousands," of vehicles, for which National Grid already charges customers the costs of owning, leasing,

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215 In its initial filing, National Grid stated that all strike contingency costs were incurred by Boston Gas-Essex Gas (Exh. NG-MDL-2-Boston Gas at 14, 34). National Grid later determined that a portion of the costs should have been allocated to Colonial Gas (Tr. 8, at 1043).

operating, and maintaining (Attorney General Brief at 110, citing Exhs. DPU-13-7, AG-1-53). The Attorney General maintains that National Grid provided no further evidence that would justify the lease of additional vehicles for strike contingency activities (Attorney General Brief at 110). In addition, the Attorney General asserts that because the Companies failed to justify inclusion of the vehicle lease costs as part of the record during the proceeding, National Grid improperly attempts to introduce additional evidence on brief (Attorney General Reply Brief at 61-62, citing National Grid Brief at IX.16). Instead, the Attorney General contends that the proper avenue for introduction of new evidence is by filing of a motion to admit evidence post-hearing (Attorney General Reply Brief at 62, citing D.T.E. 02-24/25, at 11-13). Nonetheless, the Attorney General asserts that, even had National Grid submitted the appropriate motion, the information would have not qualified as admissible post-hearing evidence (Attorney General Reply Brief at 62, citing D.T.E. 02-24/25, at 12-13). Thus, the Attorney General contends that the Department should deny National Grid's proposal to include the vehicle lease costs in strike contingency cost recovery (Attorney General Reply Brief at 61).

b. UWUA

UWUA argues that National Grid inappropriately attempts to justify the vehicle leases by asserting that unmarked cars were necessary because striking union workers may attempt to divert or disrupt the work of non-union employees or put the safety of managers at risk (UWUA Reply Brief at 3-4). UWUA asserts that there has not been a strike since the petitioning companies were acquired by National Grid and, thus, National Grid's argument is merely defamatory speculation (UWUA Reply Brief at 4). UWUA asks that the statements be stricken from the Company's brief as without record foundation (UWUA Reply Brief at 4).

c. National Grid

National Grid argues that the Attorney General's request to deny recovery of certain strike contingency costs is not warranted because all of the Companies' proposed strike contingency costs are consistent with Department precedent that allows such expenses to be included in a company's cost of service (National Grid Brief at IX.15, citing Boston Gas Company, D.P.U. 93-60, at 137-138 (1993)). With respect to employee-related expenses challenged by the Attorney General, National Grid asserts that the strike contingency preparations were performed by service company employees who do not normally perform distribution-related activities for National Grid (National Grid Brief at IX.16, citing Exhs. DPU-13-8; DPU-13-9). National Grid further contends that of the $260,000 in labor costs, only $10,000 represents straight-time pay to service company employees and the remainder relates to overtime pay incurred during the strike contingency preparations (National Grid Brief at IX.16, citing Exh. NG-MDL WP 10). National Grid asserts that overtime-related expenses are permitted by the Department as costs that a company would not normally incur (National Grid Brief at IX.17, citing D.P.U. 93-60, at 136-138).

In addition, National Grid contends that, even though it has a large fleet inventory, it is necessary to reserve additional vehicles for lease when engaged in strike contingency activities (National Grid Brief at IX.16). National Grid contends that the bulk of the vehicles in its inventory are visibly marked with the National Grid logo, which may draw undue attention from the striking union who may then attempt to divert or disrupt the non-union employees who have been assigned to perform union work (National Grid Brief at IX.16). To protect the safety and security of non-union employees and the public, National Grid asserts that it leases unmarked vehicles to reduce the risk of such undue attention and ensure that management employees assigned to perform union duties are able to complete critical safety work in a timely and safe manner (National Grid Brief at IX.16). National Grid also maintains that it leases a small number of vehicles for use by senior officers and members of the negotiating committee due to safety concerns for these individuals and their family members because the make, model, and license plate numbers of their personal vehicles may be known by striking workers (National Grid Brief at IX.16).

With respect to the proposed amortization period, National Grid asserts that its proposal to amortize the strike contingency expenses over three years tracks the length of the union contract (National Grid Brief at IX.15). National Grid maintains that its amortization period is therefore consistent with Department precedent (National Grid Brief at IX.15).

3. Analysis and Findings

The Department has not allowed companies to recover expenses incurred as a result of strikes on the grounds that they are non-recurring in nature. D.P.U. 93-60, at 136-138; Boston Edison Company, D.P.U. 1350, at 90 (1983); Cambridge Electric Light Company, D.P.U. 1015, at 21 (1982). Nonetheless, the Department has found that preparation for a potential labor strike is essential to ensure that a company is able to continue to operate in the event of a strike. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65-66.

Moreover, the Department has determined that a company may need to update or develop new strike contingency plans each time it negotiates a labor contract. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65-66. National Grid was engaged in contract negotiations during the test year, and thus the Department finds that the strike contingency costs in this instance are recurring. See D.T.E. 01-56, at 65-66.

The Attorney General argues that the Department should disallow $312,473 in employee labor-related costs and $64,200 in vehicle lease costs (Attorney General Brief at 109-110). In this instance, the bulk of employee labor-related costs incurred by National Grid related to overtime pay for non-union staff being trained on the use of critical equipment necessary to ensure the continuation of safe operations during a strike (Exh. NG-MDL-1, at 34). It is critical that National Grid be able to continue operations in the event of a strike and the training of appropriate personnel to undertake the operations is a necessary component of that preparation. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65-66. Thus, we find that the employee labor-related costs appropriately qualify as strike contingency costs.

With respect to the vehicle lease costs, National Grid has argued on brief that the leases were required due to potential disruptions by union employees (National Grid Brief at IX.16). The Attorney General and UWUA ask that the Department reject the Companies' argument as an attempt to introduce extra-record evidence with no foundation (Attorney General Reply Brief at 61; UWUA Reply Brief at 4). While there may be legitimate security concerns that would warrant National Grid's leasing of replacement vehicles, National Grid has not, in this case, demonstrated such. National Grid was provided with ample opportunity during the hearings to justify its vehicle lease costs and failed to do so (see, e.g., Tr. 8, at 1050-1051; Tr. 17, at 2463). Thus, we find that National Grid failed to demonstrate that the vehicle lease costs are reasonable and necessary to adequately prepare for a potential labor strike.[216] As such, we disallow $64,200 in vehicle lease costs.

During the proceeding, National Grid proposed to establish a regulatory asset for its strike contingency costs and then amortize the regulatory asset over a three-year period (Exhs. NG-MDL-1, at 14; DPU-10-1; Tr. 8, at 1043). A regulatory asset is created when regulators provide reasonable assurance of the creation of an asset, i.e., when a company capitalizes all or part of an incurred cost that would otherwise be expensed and the regulators allow recovery of revenue at least equal to that cost. Western Massachusetts Electric Company, D.P.U. 94-8-CC (Phase I) at 11 n.13 (1994). The Department has previously permitted companies to establish regulatory assets in limited circumstances. For example, the Department has authorized the recording of a regulatory asset to avoid significant reductions to stockholders' equity that result from the recognition of liabilities associated with pension and PBOP obligations. See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 58-59 (2009); Fitchburg Gas and Electric Light Company, D.T.E. 02-83, Letter Order at 1 (December 20, 2002). The Department has not permitted companies to establish regulatory

216 UWUA asks that the statements relating to security disruptions be stricken from National Grid's Brief as defamatory and without record foundation (UWUA Reply Brief at 4). Rather than strike the language from National Grid's Brief, the Attorney General's Reply Brief, and UWUA's Reply Brief, the Department is simply not relying on the unsupported statements in this Order.

assets for strike contingency costs because to do so would imply an intent to guarantee full recovery of the costs. Instead, strike contingency costs are normalized so that a representative amount is included in the utility's cost of service. D.T.E. 03-40, at 177-178; D.T.E. 01-56, at 66.[217] Therefore, the Department denies National Grid's request to establish a regulatory asset for strike contingency expense.

With respect to the normalization period, National Grid asserts that a three-year period is appropriate because it is based on the length of the union contract ultimately negotiated with the specific union (National Grid Brief at IX.15; Exh. NG-MDL-1, at 34-35; Tr. 8, at 1043). All of the current union contracts are for a three-year period (RR-AG-39). Thus, the Department will normalize the strike contingency costs over three years.

In reallocating a portion of the strike contingency costs from Boston Gas to Colonial Gas, National Grid did not provide documentation explaining the specific breakdown of each component. Thus, in determining the amount of vehicle lease cost to remove from each Company's cost of service, we rely on the percentage as allocated to each Company. Specifically, National Grid allocated facilities costs, of which vehicle lease costs are a component, to each Company as follows: 93.58 percent to Boston Gas-Essex Gas and 6.42 percent to Colonial Gas (see Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 31; NG-MDL-2-Colonial Gas (Rev. 3) at 47). Thus, in disallowing the $64,200, we remove a proportional amount from each Company, with $60,078 being disallowed for Boston Gas-Essex Gas and

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217 Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative level of the particular expense in cost of service. See D.P.U. 07-71, at 103; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; Nantucket Electric Company, D.P.U. 91-106/91-138, at 20-21 (1991).

$4,122 being disallowed for Colonial Gas. Accordingly, Boston Gas-Essex Gas' proposed cost of service shall be decreased by $20,026, and Colonial Gas' proposed cost of service shall be decreased by $1,374.

K. Rate Case Expense

1. Introduction

Initially, National Grid estimated that it would incur rate case expenses as follows: (1) $1,731,840 for Boston Gas/Essex Gas; and (2) $897,242 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 1) at 32; NG-MDL-2-Colonial Gas (Rev. 1) at 31). National Grid's proposed rate case expenses include: (1) legal representation; (2) research and preparation of a revenue-decoupling mechanism; (3) a productivity and cost study to support the requested inflation adjustment pursuant to the proposed decoupling mechanism; (4) research and preparation of a depreciation study; (5) research and preparation of the cost of capital analysis; (6) the preparation of a lead/lag study; (7) research and preparation of allocated and marginal cost of service studies and associated rate design; (8) revenue requirements support; and (9) other associated services and resources required to complete the case, including temporary help, transcripts, notices, delivery and copying costs (Exh. NG-MDL-1, at 35-36; RR-DPU-46(A) (Supp. 3) at 2-5). Based on its final invoices and estimated invoices[218] to complete the compliance filing, National Grid proposes a total rate case

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[218] As discussed below, National Grid provides the following estimates to complete the compliance filing: $74,268 for Boston Gas-Essex Gas and $37,134 for Colonial Gas (RR-DPU-46(A) (Supp. 3) at 1, 2).

expense of $2,187,216[219] for Boston Gas-Essex Gas and $1,188,815 for Colonial Gas (RR-DPU-46(A) (Supp. 3), at 1, 2).[220]

National Grid issued requests for proposals ("RFPs") for consultants to provide the following services: (1) net inflation/productivity study; (2) cost of capital analysis; (3) rate design/marginal cost/allocated cost of service study; (4) revenue decoupling proposal; (5) rate case training; (6) depreciation and lead/lag studies; (7) revenue requirements analysis; and (8) legal services (Exh. DPU-3-1). National Grid proposes to normalize its rate case expense over five years for both Boston Gas-Essex Gas and Colonial Gas (Exh. NG-MDL-1, at 38). Normalizing the proposed rate case expense of $2,187,216 for Boston Gas-Essex Gas over five

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219 National Grid's final revenue requirement schedules indicate that the total rate case expense for Boston Gas-Essex Gas is $2,219,330, which is $32,114 more than stated in RR-DPU-46(A) (Supp. 3) (see Exh. NG-MDL-1 (Rev. 3) at 32; RR-DPU-46 (A) (Supp. 3) at 1). National Grid does not provide an explanation for this discrepancy, but it appears that the difference lies in the allocated cost of service studies, rate design, and legal fees components of rate case expense (see Exh. NG-MDL-1 (Rev. 3) at 32; RR-DPU-46 (A) (Supp. 3) at 1). Given that the Department designated RR-DPU-46 as the means by which National Grid was to report updated rate case expense, we will accept the lesser totals reported in that document. Additionally, the totals reported in RR-DPU-46(A) (Supp. 3) are, with the exceptions noted below, supported by invoices submitted in this proceeding.

220 National Grid's final revenue requirement schedules indicate that the total rate case expense for Colonial Gas is $1,204,871, which is $16,056 more than stated in RR-DPU-46(A) (Supp. 3) (see Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 31; RR-DPU-46 (A) (Supp. 3). National Grid does not provide an explanation for this discrepancy, but it appears that the difference lies in the allocated cost of service studies, rate design, and legal fees components of rate case expense (see Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 31; RR-DPU-46 (A) (Supp. 3) at 2). Given that the Department designated RR-DPU-46 as the means by which National Grid was to report updated rate case expense, we will accept the lesser totals reported in that document. Additionally, the totals reported in RR-DPU-46(A) (Supp.3) are supported by invoices submitted in this proceeding.

years produces an annual expense of $437,443 (see RR-DPU-46(A) (Supp. 3) at 1). Normalizing the proposed rate case expense of $1,188,815 for Colonial Gas over five years produces an annual expense of $237,763 (see RR-DPU-46(A) (Supp. 3) at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that National Grid has not met its burden to justify full recovery of rate case expenses for certain outside consulting services and for legal services (Attorney General Brief at 131). First, the Attorney General contends that National Grid is improperly attempting to recover approximately $68,000 in rate case training expenses as part of rate case expense (Attorney General Brief at 132-133). According to the Attorney General, such training expenses have traditionally been included in the cost of service, separate from rate case expense (Attorney General Brief at 133, citing D.P.U. 09-30, at 270-272; Model Terms and Conditions for the Electric Industry, D.P.U./D.T.E. 97-65, at 21-23 (1997); D.P.U. 92-111, at 128-130).

Additionally, the Attorney General claims that rate case training is a nonrecurring, non-extraordinary expense that is not specific to this rate case (Attorney General Brief at 133). The Attorney General argues that National Grid has not demonstrated that the expense is recurring because such training was not previously undertaken and the Companies will not enter into recurring rate case training contracts (Attorney General Brief at 134-135, citing D.T.E. 98-51, at 39; Tr. 6, at 716, 802). Further, the Attorney General asserts that the rate case training expense is not extraordinary compared to the Companies' gas distribution revenue of approximately $664,677,523 (Attorney General Brief at 134, citing Exhs. NG-MDL-2-Boston Gas at 1, NG-MDL-2-Colonial Gas at 1). Additionally, the Attorney General notes that the training was attended both by employees who did and did not perform work on the instant case (Attorney General Brief at 134, citing Tr. 6, at 716; Attorney General Reply Brief at 65, citing Tr. 6, at 716). Thus, the Attorney General asserts that National Grid cannot support the position that it has submitted for recovery only those costs incurred to train employees participating in this rate case (Attorney General Reply Brief at 65). Finally, the Attorney General argues that, because the training was viewed as a long-term investment for National Grid with benefits that will carry over to future rate cases, classifying these expenses as rate case expenses is improper (Attorney General Brief at 134, citing Tr. 6, at 716; Attorney General Reply Brief at 65, citing Tr. 6, at 716).

Alternatively, the Attorney General argues that the rate case training was imprudently incurred (Attorney General Brief at 135). The Attorney General contends that, given that Essex Gas and Colonial Gas were under ten-year rate freezes, it was foreseeable that National Grid would file at least one base rate case sometime around 2010 on behalf of these Companies and, therefore, would need to retain knowledgeable revenue requirement staff (Attorney General Brief at 136). The Attorney General claims that, nevertheless, National Grid neither retained sufficiently experienced revenue requirement staff nor hired new, well-trained employees to serve as revenue requirements staff (Attorney General Brief at 136; Attorney General Reply Brief at 65). The Attorney General notes that although National Grid's electric affiliates were also coming out of long-term rate plans, they did not attempt to recover any rate case training in their electric rate cases (Attorney General Brief at 136, citing D.P.U. 09-39, at 278-279).

Next, the Attorney General argues that expenses associated with revenue requirements support and the inflation productivity study should be disallowed because the Companies failed to engage these consultants through competitive bidding (Attorney General Brief at 137-138, 142, 144). The Attorney General contends that, although National Grid issued an RFP to four consultants to prepare the revenue requirement, it instead used in-house personnel to prepare the revenue requirement and, additionally, engaged revenue requirement support services which were not competitively bid (Attorney General Brief at 138-139, citing Exhs. AG-8-7, DPU-15-15). The Attorney General argues that the Company has not shown the need for revenue requirement support services. Further, the Attorney General argues that National Grid has not presented evidence to support the consultant's selection (Attorney General Brief at 139-140; Attorney General Reply Brief at 66). The Attorney General asserts that the Companies, rather than ratepayers, are the beneficiaries of this work, and ratepayers should not have to bear special, incremental charges for work the Company normally performs itself (Attorney General Reply Brief at 66, citing D.T.E. 05-27, at 161). Finally, the Attorney General submits that the combination of rate case training expenses to prepare the revenue requirement along with consultant expenses to review that same revenue requirement is unreasonable and imprudent (Attorney General Brief at 140).

With respect to the inflation productivity study, the Attorney General argues that although the Companies negotiated a discount with the consultant, this discount was offset by a nearly 78 percent cost overrun (Attorney General Reply Brief at 67, citing RR-DPU-46(A) (Supp. 2) at 1-2). Further, the Attorney General contends that there was no competitive pressure to control costs and that the Companies should have employed a cost containment strategy for this consultant's services and insisted on a price cap for these services (Attorney General Reply Brief at 67). Thus, the Attorney General argues that National Grid has failed to contain rate case expenses, and thus shareholders should bear the burden of this failure (Attorney General Reply Brief at 67). Alternatively, the Attorney General asserts that the Department should limit recovery of the inflation productivity study expenses to National Grid's original estimate (Attorney General Reply Brief at 67).

The Attorney General also argues that invoices from National Grid's consultant for expenses related to the depreciation and lead-lag studies fail to meet the Department's standard to provide invoices that sufficiently support the expense (Attorney General Brief at 141, citing Exh. DPU-3-2 (BULK), Att. at 5-40; D.T.E. 02-24/25, at 193-194). The Attorney General contends that, although the invoices contain the consultant's name and time billed, they omit the specific nature of the services provided (Attorney General Brief at 141). The Attorney General asserts that prior acceptance of similar invoices in past proceedings does not excuse a departure from Department precedent in this case (Attorney General Reply Brief at 66). Thus, the Attorney General argues that the Department should disallow recovery of all lead lag study consultant expenses that do not have the requisite information (Attorney General Reply Brief at 67).

Moving on to legal services, the Attorney General argues that legal expenses have not been reasonably or prudently incurred (Attorney General Brief at 144). The Attorney General notes that most law firms responding to the RFP did not provide definitive cost estimates (Attorney General Brief at 2 (Confidential)). Further, the Attorney General states that, although the selected legal counsel was not necessarily the lowest bidder, its estimated price was reasonable (Attorney General Brief at 2-3 & n.1 (Confidential)).[221] The Attorney General contends, however, that based on the RFP response, the current estimate for legal expenses should be lower (Attorney General Brief at 2 (Confidential), citing Exh. DPU 3-1(H) at 112-113). The Attorney General contends that legal counsel failed to accurately estimate the number of hours it would take to complete this case and, therefore, recovery of legal fees should be limited to counsel's initial estimate (Attorney General Brief at 2-3 & n.1 (Confidential), citing Exh. AG 8-17(A) (Supp.) at 1-2)).

Finally, the Attorney General argues that the Department should normalize rate case expenses consistent with Department precedent (Attorney General Brief at 145-146, citing Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 76-77 (2009)). According to the Attorney General, the Department determines the appropriate period for recovery of rate case expense by taking the average of the interval between filing dates of a company's last four rate cases and rounding to the nearest whole number (Attorney General Brief at 145, citing, e.g., D.P.U. 09-39, at 296, D.P.U. 09-30, at 241; D.P.U. 08-27, at 75-76). The Attorney General contends that application of Department precedent results in a six-year normalization

221 The Department will cite to portions of the Attorney General's confidential brief that do not reveal confidential information.

period rather than the five-year period proposed by National Grid (Attorney General Brief at 145).

b. National Grid

National Grid argues that it conducted competitive solicitations for expenses associated with rate case training and the consultant that performed the revenue requirement support service (National Grid Brief at IX.36). National Grid contends that costs associated with both of these services are reasonable because, by incurring these costs, the Companies were able to avoid using an outside consultant to develop the entire cost of service and to litigate multiple revenue requirements analyses (National Grid Brief at IX.36, citing Exh. AG-15-11; Tr. 6, at 714-718). Accordingly, National Grid argues that it was able to substantially reduce rate case expense (National Grid Brief at IX.36).

Regarding rate case training costs, National Grid argues that it seeks recovery of only the expenses incurred for employees who actually worked on the instant rate case (National Grid Brief at IX.36). Moreover, National Grid asserts that the consultant who performed the rate case training is a now-retired Boston Gas employee who testified in Boston Gas' last rate case, D.T.E. 03-40 (National Grid Brief at IX.36-37, citing Exh. DPU-15-11). Thus, National Grid contends that the consultant trained the Companies' employees to use his revenue requirement model, which has been used in previous proceedings and is directly related to this rate case (National Grid Brief at IX.37, citing Exh. DPU-15-11).

National Grid disputes that invoices submitted by its lead-lag study consultant do not contain sufficient documentation of the services performed (National Grid Brief at IX.37).

Instead, National Grid asserts that most of the invoices reference activity performed, such as "data requests" or "hearings" (National Grid Brief at IX.37, citing RR-DPU-46 (Supp. 2)). Additionally, National Grid argues that this consultant has provided services in prior rate cases before the Department and its invoices have never been found to be insufficient to document incurred costs; thus, it would be arbitrary for the Department to now require more specific descriptions of services rendered, although it could do so for future proceedings (National Grid Brief at IX.37). National Grid contends that there is no dispute over the amount of work performed, the quality of work, hourly rates, or overall cost of service (National Grid Brief at IX.37; National Grid Reply Brief at 111). National Grid asserts that the costs were not excessive, unwarranted, or incurred in bad faith, and, therefore, the expenses should not be disallowed (National Grid Reply Brief at 111, citing Boston Gas Company v. Department of Public Utilities, 387 Mass. 531, 539 (1982) (citations omitted); New England Telephone & Telegraph Company v. Department of Public Utilities, 360 Mass. 443, 484 (1971)).

With respect to services performed by its inflation productivity study consultant, National Grid argues that it issued a competitive solicitation and determined that the selected consultant would be the best situated to perform the study within the required time frame and at a reasonable cost because he had previously performed productivity studies for Boston Gas in D.P.U. 96-50 and D.T.E. 03-40 (National Grid Brief at IX.38, citing Exh. DPU-15-2). Further, National Grid argues that it negotiated a price discount with this consultant (National Grid Brief at IX.38, citing RR-DPU-31). In response to the Attorney General's claims that these costs should be denied because they exceed the initial estimate by a substantial amount, National Grid argues that the driver of cost changes between the pre-filing estimate and final cost was the need to respond to discovery, record requests, and a conference call to respond to the Attorney General's expert testimony (National Grid Reply Brief at 111, citing Exhs. AG-5-1 (Supp.); AG-5-6 (Supp.); AG-5-7 (Supp.); AG-5-8 (Supp.); AG-5-9 (Supp.); AG-5-10 (Supp.); AG-5-11 (Supp.); AG-5-12 (Supp.)). As the costs are not excessive, unwarranted, or incurred in bad faith, National Grid asserts that they should not be disallowed (National Grid Brief at IX.38, citing D.P.U. 09-30, at 232-233; National Grid Reply Brief at 112).

Next, National Grid argues that the Attorney General miscalculates the total, upper-end estimate to provide legal services (National Grid Brief (Confidential) at 1). According to National Grid, the upper-level estimate the Attorney General relies upon is not the total estimated cost to perform legal service as contained in the RFP response but only a portion of the stated time to complete the case (National Grid Brief (Confidential) at 1). National Grid explains that the current total estimated cost to provide legal services consists of a number of different components in addition to the upper-level estimate relied upon by the Attorney General, including paralegal time to produce various filings (National Grid Brief (Confidential) at 1-2, citing Exh. DPU 3-1(H) at 11). Thus, National Grid argues that there is no misunderstanding regarding the total estimate to perform legal services (National Grid Brief (Confidential) at 2). Finally, National Grid claims that although its legal counsel will exceed the estimated hours to complete the case, legal expense will not substantially exceed the current estimate and will remain on par with the estimated costs of other bidders (National Grid Brief (Confidential) at 3).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has been actually incurred and, thus, is considered known and measurable. D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62.[222] Second, such expenses must be reasonable, appropriate, and prudently incurred. D.T.E. 05-27, at 160-161; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. 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. We note that the proposed rate case expenses in this proceeding are the largest that the Department has ever been asked to approve.

Rate case expense, like any other expenditure, is an area where 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; D.P.U. 96-50 (Phase I) at 79. The Department will continue to scrutinize the overall level of rate case expense and may require shareholders to shoulder a portion of the expense. D.P.U. 08-35, at 135. 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. See D.P.U. 93-233-B at 16.

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222 While petitioners may seek recovery of rate case expense incurred on a fixed-fee basis for work performed after the close of the evidentiary record (e.g., for completion of necessary compliance filings), the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 02-24/25, at 196.

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.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. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. If a petitioner decides to forgo the competitive bidding process, it must provide an adequate justification for its decision to do so. D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79.

While the Attorney General questions the solicitation process undertaken for the inflation productivity study and revenue requirement support, she does not question the solicitation process for the remaining witnesses. The Department has reviewed the RFP processes for the uncontested witnesses, and we determine that National Grid conducted a fair, open, and transparent competitive bidding processes for such witnesses (Exhs. DPU-3-1, Atts. (A)-(H)). The solicitation processes for the net inflation witness and revenue requirement support are discussed below.

ii. Inflation Productivity Study

The Attorney General argues that expenses associated with the inflation productivity study should be disallowed because the Companies failed to retain the consultant through competitive bidding as required by Department precedent and, therefore, failed to demonstrate the reasonableness of these costs (Attorney General Brief at 144). National Grid responds that it (1) conducted a competitive solicitation; (2) used a consultant who had previously performed productivity studies for Boston Gas; and (3) negotiated a discount with the consultant (National Grid Brief at IX.38, citing Exh. DPU-15-2; RR-DPU-31).

As noted above, the Department has consistently emphasized the importance of competitive bidding for outside services in a company's overall strategy to contain rate case expense. See, e.g., D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. A company must engage in a competitive bidding process to engage outside rate case services. D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. Any decision to forgo the competitive bidding process must be adequately justified. D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79.

National Grid issued an RFP for an inflation productivity study consultant to three potential bidders on March 12, 2010, approximately one month before it filed the instant rate case on April 16, 2010 (Exhs. DPU-3-1; DPU-3-1, Att. (A) at 1; DPU-15-2; Tr. 6, at 708). However, the record demonstrates that National Grid first contacted its chosen consultant prior to the issuance of the RFP and engaged the consultant in discussions about whether he could perform the productivity study in a timely fashion (Exhs. DPU-15-1, at 2; DPU-15-2; Tr. 6, at 710). Further, prior to issuing the RFP, National Grid received an estimate of the consultant's costs (Exhs. DPU-15-2; Tr. 6, at 710). Concerned that the consultant's estimate was high, National Grid states that it issued an RFP to evaluate the reasonableness of its consultant's estimated costs (Exh. DPU-15-2; Tr. 6, at 710).[223]

The scope of work in the RFP required the consultant to perform an analysis of the O&M productivity trends for both national and regional gas distribution utilities; an analysis of O&M input price trends relative to inflation; a report summarizing the productivity of Boston Gas-Essex Gas and Colonial Gas, and testimony concerning the mathematics underlying adjustment mechanisms and the study's results (Exh. DPU-3-1, Att. (A) at 3-4). The responses to the RFP were due on March 19, 2010, while the instant rate case was submitted, with testimony describing the net inflation productivity study, on April 16, 2010 (Exhs. DPU-3-1, Att. (A) at 8; NG-LRK-1). Thus, even if National Grid had evaluated the bids and engaged the consultant within a matter of days after bids were received, the chosen consultant would have had just three weeks to perform the research and analysis, prepare the study, and prepare the testimony supporting the study. Not surprisingly, only the consultant whom National Grid initially engaged to perform the inflation productivity study responded to the RFP (Exh. DPU-15-2, at 1).

Based on these facts, the Department concludes that National Grid did not conduct a competitive solicitation for the inflation productivity study. Although National Grid issued an RFP to three consultants, it had already engaged one of these consultants in discussions to perform the inflation productivity study (Exh. DPU-15-2; Tr. 6, at 710). The scope of work

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223 Notably, National Grid initially stated that it used a sole source process to select its consultant (Exh. DPU-3-3). It later stated that it issued the RFP to a total of three consultants to evaluate the reasonableness of costs of the consultant with whom it had first negotiated (Exh. DPU-15-2; Tr. 6, at 710).

required for an inflation productivity study is such that it was unreasonable for otherwise potentially competitive consultants to develop the needed studies and testimony within the weeks before the rate case was filed. Given the significant scope of work, the late date that National Grid issued the RFP, and the fact that it had already negotiated with its chosen consultant, the Department concludes that the solicitation was not issued in a manner that would reasonably result in the procurement of competitive bids.

National Grid was on notice that it was required to engage in a competitive bidding process for its non-legal and legal service providers or adequately justify the reasons for noncompliance. See D.P.U. 09-39, at 287; D.P.U. 09-30, at 230; D.P.U. 08-35, at 114; D.P.U. 07-71, at 101-102; D.P.U. 03-40, at 153.[224] As the Department noted in D.P.U. 09-30, at 230, the requirement of having to submit a competitive bid in a structured and organized process serves several important factors. First, it provides the Department with an objective method to determine whether the services could be adequately provided at lower costs. D.P.U. 09-30, at 230; D.T.E. 03-40, at 151. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 09-30, at 230; D.P.U. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 09-30, at 230; D.T.E. 03-40, at 152-153.

[224] The Department had previously determined that Boston Gas had not observed the Department's directives regarding competitive bidding as a method for cost containment in rate cases. D.T.E. 03-40, at 153. There, Boston Gas failed to competitively solicit its legal and consulting services. D.T.E. 03-40, 152-153. Although the Department accepted its justifications for doing so, we noted that a company electing to secure outside services for rate case expense must engage in a structured, objective competitive bidding process for these services. D.T.E. 03-40, at 153.

The Companies also must demonstrate that the choice of consultant is both reasonable and prudent. See D.P.U. 09-30, 231-232; D.T.E. 03-40, at 153. Further, companies are on notice that the risk of non-recovery of rate expense expenses looms should they fail to sustain their burden to demonstrate cost containment associated with the selection and retention of outside service providers. D.P.U. 09-39, at 290-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 153.

In this case, with respect to the inflation productivity study consultant, we find that National Grid has failed to justify its departure from the requirement to conduct a competitive solicitation. Without such solicitation as a benchmark, we find that National Grid has failed to demonstrate the reasonableness of these costs.

National Grid has had a long-term relationship with this consultant and the consultant has institutional knowledge of Boston Gas (Exhs. DPU-15-1; DPU-15-2). Here, however, where there are concerns about the level of the consultant's costs, we find that such considerations are insufficient to obviate the need for a competitive bidding process. See D.P.U. 07-71, at 100-101. National Grid was itself concerned about the consultant's cost estimate, as evidenced by it issuing an RFP only weeks before it filed this case (see Exh. DPU-15-2, at 1; Tr. 6, at 710). Following the unsuccessful RFP process, National Grid again expressed concern that the consultant's costs were high compared with studies performed by other companies (Exh. AG-8-10, Att. AG 8-10(B)).

Without another bid against which the Department can evaluate the cost to conduct this study, the Department has no basis to evaluate National Grid's claim that the selected consultant's previous work on Boston Gas' PBR made him most likely to perform the study at a reasonable costs (Exh. DPU-15-2; see D.P.U. 09-30, at 230; D.T.E. 03-40, at 151). As noted above, a competitive RFP keeps a consultant from taking the relationship with a company for granted. D.P.U. 09-30, at 230; D.T.E. 03-40, at 152.

National Grid admits that that it did not have a comparably situated economic expert against which to benchmark the proposed price (RR-DPU-31). It then sought and obtained a percentage discount that it states was in line with discounts obtained from other consultants (RR-DPU-31). However, without a basis to assess how reasonable the original estimate was, National Grid's ability to negotiate a percentage discount on an estimate does not provide the Department with a sufficient basis to conclude that the proposed costs are reasonable.

Accordingly, having found that National Grid has failed to adequately justify its reasons for failing to engage in a competitive bidding process for its net inflation productivity consultant, we disallow these expenses.

iii. Revenue Requirement Support

The Attorney General argues that the Companies failed to demonstrate the need for revenue requirements support services and, further, failed to competitively bid such services (Attorney General Brief at 138-140). National Grid responds that it did competitively procure this service and that, in combination with the rate case training provided to its employees, it substantially reduced rate case expense (National Grid Brief at IX.36).

National Grid issued an RFP to perform the revenue requirement calculation (Exh. DPU-15-15). Ultimately, National Grid chose to perform the revenue requirement calculation in–house and, therefore, did not award a contract pursuant to the RFP (Exh. DPU-15-15). National Grid, however, determined that an experienced consultant still was needed to perform a review of the internally generated revenue requirements workpapers (Exh. DPU-15-15). At that point, National Grid chose to retain one of the consultants that responded to the RFP for the revenue requirement (Exh. DPU-15-15). The chosen consultant was not the lowest bidder (Exh. DPU-3-1, Att. (G) at 49, 73). National Grid, however, explains that it selected the consultant based upon: (1) the unavailability of the other vendor that responded to the RFP; (2) the proximity of the selected consultant to the Companies' offices; and (3) the experience of the selected consultant (Exh. DPU-15-15).

Although National Grid did not issue a second RFP for the revenue requirement support services, it did issue an RFP to perform the full revenue requirement analysis (Exhs. DPU-3-1, Att. (G); DPU-15-15). Both issues are closely related and, therefore, we conclude that conducting a separate RFP for revenue requirement support services would have been an inefficient use of the Companies' resources. See D.P.U. 09-30, at 232. The consultant selected to perform the revenue requirement support service had responded to the aforementioned RFP (Exh. DPU 3-1, Att. (G) at 50-73; DPU-15-15). Thus, the RFP process adequately established a benchmark for the capabilities, approach, and pricing offered by the provider selected to perform the revenue requirement support service (Exh. DPU 3-1, Att. (G) at 50-73). We conclude, therefore, that National Grid has adequately supported its selection of the revenue requirements support consultant (see Exh. DPU-15-15).

Additionally, based upon initial estimates to prepare a full revenue requirement analysis, the Department recognizes that National Grid to some degree reduced rate case expense associated with this work by performing the revenue requirement calculation in-house (see Exh. DPU 3-1, Att. (G) at 49, 73). Further, we find that the services provided by the revenue requirement support consultant, while related to the revenue requirement calculations performed in-house, were sufficiently necessary given the complexity of this proceeding to warrant inclusion in rate case expense. Accordingly, we conclude that the revenue requirement support expenses were reasonable, prudent, and appropriate.[225]

c. Various Rate Case Expenses

i. Introduction

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.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194; D.T.E. 01-56, at 75; D.T.E. 98-51, at 61; D.P.U. 96-50 (Phase I) at 79. Further, we have stated that failure to provide this information could result in the Department's disallowance of all or a portion of rate case expense. D.T.E. 02-24/25, at 193; D.P.U. 96-50 (Phase I) at 79.

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225 On brief, National Grid repeatedly claims that costs must be allowed absent evidence that they are excessive, unwarranted, or incurred in bad faith (see, e.g., National Grid Brief at IX.38). National Grid misstates the standard of review, which places the burden on the Companies to establish that its costs are reasonable, appropriate, and prudently incurred. See D.T.E. 05-27, at 160-161; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

ii. Lead-Lag Consultant Invoices

The Attorney General argues that invoices provided by National Grid's lead-lag study consultant fail to meet the Department's requirements for detailing the nature of the services performed (Attorney General Brief at 141-142). A review of those invoices demonstrates that, minimally, they each refer to specific projects upon which the consultants worked (e.g., "Boston Gas, Lead Lag-Study," "Essex Gas, Lead-Lag Study," etc.) (Exhs. DPU-3-2, at 26, 27). Further, some invoices also designate whether the service was related to the hearings, data requests, or record requests (RR-DPU-46(B) (Supp. 2) at 1-6). The Department is familiar with the nature of the effort expended on these types of activities and, therefore, we will permit recovery of the costs here. Going forward, however, we remind companies that consultants must include sufficient detail in rate case expense invoices that describes work that has been completed. Failure to include such detail will result in the expenses being disallowed. See D.T.E. 96-50 (Phase I) at 79; D.T.E. 02-24/25, at 193.

iii. Rate Case Training

National Grid seeks to recover $66,866 in rate case expense related to rate case training it conducted to train the Companies' employees to perform the revenue requirement calculation (Tr. 6, at 715). The Attorney General contends that rate case training is a nonrecurring, non-extraordinary expense that should be disallowed (Attorney General Brief at 133, 135). National Grid argues that the cost of the training was reasonable in that, in conjunction with the revenue requirement support services, it was able to avoid using an outside consultant to develop the entire cost of service and to litigate multiple revenue requirements analyses (National Grid Brief at IX.36, citing Exh. AG-15-11; Tr. 6, at 714-718).

National Grid acknowledges that it has not conducted rate case training before and that its employees will now be able to perform the revenue requirement calculation in the future (Tr. 6, at 802, 716). The Department finds that National Grid's rate case training was a one-time expense that will benefit the Companies as well as National Grid's electric distribution companies in the future. Further, the Department finds that $66,866 in rate case training expense is not extraordinary compared to the Companies' gas distribution revenue (see Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 1; NG-MGL-2-Colonial Gas (Rev. 3) at 1). Thus, the Department concludes that National Grid's rate case training is a nonrecurring, non-extraordinary expense that is not properly included in rate case expense. Accordingly, based upon final invoices, we disallow $66,866 incurred for rate case training, which is allocated as $44,577 for Boston Gas-Essex Gas and $22,289 for Colonial Gas (RR-DPU-46 (A) (Supp.3) at 1, 2).

iv. Legal Services

The Attorney General asserts that legal services expenses have not been reasonably or prudently incurred and that it is unclear how legal counsel derived its current cost estimate (Attorney General Brief at 144). National Grid maintains that the Attorney General miscalculated the total upper limit of legal counsel's cost estimate (National Grid Brief (Confidential) at 1).

We find that legal counsel's calculation of costs for legal services is consistent with the method outline in its estimate (see, e.g., Exh. DPU 3-1. Att. (H) (Confidential) at 11, 112, 113; RR-DPU-46(A) (Supp.1) at 4, n.3 & 4). We conclude that the cost estimate and fee agreement terms contained in counsel's response to the RFP were competitive with other bidders and that National Grid's bid evaluation was reasonable, prudent, and appropriate (see Exh. DPU 3-1, Att. (H) (Confidential) at 11).

National Grid has appropriately provided invoices delineating a total of $1,298,938 in costs related solely to legal expenses (RR-DPU-46(A) (Supp.3) at 3, column (B)). In addition, National Grid claims as part of legal expenses, $325,757 in costs associated with reimbursable rate case expense.[226]

National Grid has appropriately delineated the vast majority of these legal expenses (including reimbursable expenses) by providing appropriate invoices (Exh. DPU-15-19, Att. (A); RR-DPU-46(C) (Supp. 1); RR-DPU-46(B) (Supp. 2); RR-DPU-46(B-D) (Supp. 3). With the exception of certain expenses as discussed below, we determine that such expenses are reasonable, appropriate, and prudently incurred.

National Grid seeks to recover $48,966 for transcription services as part of reimbursable rate case expense for legal services (RR-DPU-46(A) (Supp.3) at 7). Although bills from counsel to National Grid reflect this total amount, the Companies have provided invoices that total only $13,931 for transcription services (RR-DPU-46(D) (Supp. 1);

226 These services consist of courier service, copy charges, transcription services, filing fees, overnight mail, postage, and legal notices (RR-DPU-46(A) (Supp.3) at 3, column (C)).

RR-DPU-46(B) (Supp.2.) at 48; RR-DPU-46(B) (Supp.3) at 18; RR-DPU-46(D) (Supp.3) at 1-4). National Grid has the duty to provide copies of all invoices of costs for which it seeks recovery so that the Department can properly verify the expenses. Accordingly, we disallow a total of $35,035 in expenses related to transcription services, which is allocated as $23,357 for Boston Gas-Essex Gas and $11,678 for Colonial Gas.

Finally, we note that National Grid seeks recovery of $1,101,615 in legal expenses for Boston Gas, and $550,807 in legal expenses for Colonial Gas (RR-DPU-46(A) (Supp.3) at 1, 2, 3). These calculations include $30,500 in estimated legal expenses to complete these proceedings through the compliance filing, allocated as $20,333 to Boston Gas-Essex Gas and $10,167 to Colonial Gas (RR-DPU-46(A) (Supp.3) at 3, columns (E)-(G)). In turn, in its total rate case expense calculation, National Grid again adds $30,500 (allocated as noted above) in estimated legal expenses (RR-DPU-46(A) (Supp.3) at 1, 2, 3). Thus, this amount is counted twice in the calculation of total rate case expense. Accordingly, we will remove from the legal fees component of rate case expense, $30,500, which is allocated as $20,333 for Boston Gas-Essex Gas and $10,167 for Colonial Gas.

v. Estimated Invoices

National Grid filed its final rate case expense update on September 24, 2010, which contained actual invoices for work performed through the filing of reply briefs. To provide for additional expenses necessary to complete this proceeding, National Grid proposes the following adjustments to its rate case expense for legal services and other consultants: $74,268 for Boston Gas-Essex Gas and $37,134 for Colonial Gas (RR-DPU-46(A) (Supp.3) at 1, 2, 8).[227] National Grid proposes to recover estimated rate case expense for both Boston Gas-Essex Gas and Colonial Gas for: (1) legal services (including legal services and reimbursable rate case expenses); (2) recalculating depreciation studies and preparing compliance accrual rates/studies; (3) update of lead lag studies; and (4) update of cost of service, marginal distribution study, and rate design (RR-DPU-46(A) (Supp.3) at 1, 2, 8).

The Department's longstanding precedent allows only known and measureable changes to test year expenses to be included as adjustments to cost of service. 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 projections or estimates are not known and measurable and recovery of those expenses is not allowed. 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 the recovery of rate case expense associated with compliance filing work based on a fixed fee arrangement, but the reasonableness of the fixed fees must be supported by sufficient evidence. 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 to complete a case after the record closes and briefs are filed, a company may qualify to recovery such expenses. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. We have stated that documented and itemized proof, however, is a prerequisite to recovery. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196.

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227 These totals include $16,900 for rate case services already rendered which is allocated as $11,267 for Boston Gas-Essex Gas and $5,633 for Colonial Gas (see RR-DPU-46(A) (Supp.3) at 5, 8). Invoices supporting these services were provided in the September 24, 2010, rate case update (RR-DPU-46(A) (Supp. 3) at 5,8).

National Grid estimates that it will cost $30,500 to update legal services (including an estimated $1,000 for reimbursable rate case expenses).[228] National Grid states that these estimates are based on actual hours from other recently completed rate case compliance filings and an estimate of labor hours for paralegals (30 hours) and two attorneys (35 hours each) (RR-DPU-46(A) (Supp.3) at 3 n.6).

National Grid estimates that it will cost $5,308 to update the depreciation study and $11,025 to update lead lag studies (RR-DPU-46(B) (Supp.3) at 20).[229] For the depreciation and lead lag study updates, National Grid's estimates include a description of work expected to be performed, estimated hours, and billing rate (RR-DPU-46(B) (Supp.3) at 20).

Finally, National Grid estimates that it will cost $64,569 to update the cost of service, marginal distribution study, and rate design (RR-DPU-46 (A) (Supp.3) at 1, 2, 8).[230] For the update of cost of service, marginal distribution study, and rate design, National Grid's estimates include a description of work expected to be performed, estimated hours, and billing rate (RR-DPU-46(B) (Supp. 3) at 23-24).

National Grid did not negotiate any fixed fee contracts with its rate case consultants or attorneys to complete this case (RR-DPU-46(A) (Supp. 3) at 3, 20, 22-24). Instead, National

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[228] This estimated expense is allocated as follows: $20,333 for Boston Gas-Essex Gas and $10,167 for Colonial Gas (RR-DPU-3(A) (Supp. 3) at 1-2).

[229] These estimated expenses are allocated as follows: (1) depreciation study - $3,539 for Boston Gas and $1,769 for Colonial Gas; and (2) lead lag study - $7,350 for Boston Gas and $3,675 for Colonial Gas (RR-DPU-46(A) (Supp.3) at 1, 2).

[230] This estimated expense is allocated as follows: $43,046 for Boston Gas-Essex Gas and $21,523 for Colonial Gas (RR-DPU-46(A) (Supp.3) at 1, 2, 8).

Grid bases its request solely on estimates and projections. National Grid's proposed adjustments based on projections or estimates are not known and measurable and, therefore, recovery of those expenses is not allowed. D.T.E. 01-56, at 75 (Department disallowed the estimated fees for preparation of compliance filings as not known and measurable); Blackstone Gas Company, D.T.E. 01-50, at 22 (2001). Assuming that the fixed fee agreement is properly supported, the fact that the consultant 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 the compliance filing. This level of confidence is absent here.

Consistent with longstanding precedent, because the proposed rate case expense adjustments are based upon estimates or projections to complete this proceeding, they are insufficient to demonstrate known and measureable changes that permit recovery of those expenses. D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-50, at 22; D.T.E. 01-56, at 75. Accordingly, we disallow the estimated costs to complete this proceeding, with the exception that $16,900 (allocated as $11,267 for Boston Gas-Essex Gas and $5,633 for Colonial Gas) supported by actual invoices for services rendered (see n. 227) above) will be allowed.

d. Normalization of Rate Case Expenses

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test year level to determine the adjustment. D.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 expenses so that a representative annual amount is included in the cost of service. 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 33-34. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of rate case expense. 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. 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.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 Attorney General contends that application of Department precedent results in a six-year normalization period rather than the five-year period proposed by National Grid (Attorney General Brief at 145). National Grid argues the average period between rate case filings has been 5.7 years for Boston Gas-Essex Gas and 6.7 years for Colonial Gas (National

Grid Brief at IX.35).[231] National Grid proposes a five-year normalization period for both Boston Gas-Essex Gas and Colonial Gas (National Grid Brief at IX.35).

Based on the average interval of its last four rate case filings, the Department concludes that the appropriate normalization period for Boston Gas is six years. For purposes of calculating Colonial Gas' normalization period, the Department will not consider the date of filing of D.T.E. 98-128, its merger-related rate freeze, because Colonial Gas was not seeking a rate increase in that filing. Without including the date of that filing in calculating the normalization period, the average period between rate case filings for Colonial Gas is 8.6 years. Accordingly, rounded to the nearest whole number, Colonial Gas' normalization period would be nine years. The Department concludes, however, that mechanical application of this method produces an unreasonably long normalization period. See, e.g., D.T.E. 98-51, at 55; Assabet Water Company, D.P.U. 95-92, at 20 (1996); D.P.U. 86-149, at 2 (1986). The facts of this case warrant a departure from the mathematic formula used in general Department precedent. Taking into consideration the six-year normalization period approved for Boston Gas-Essex Gas, Colonial Gas' affiliation with Boston Gas-Essex Gas, and administrative efficiency, the Department concludes that the appropriate normalization period for Colonial Gas is also six years.

4. Conclusion

National Grid has requested recovery of a total rate case expense of $2,187,216 for Boston Gas-Essex Gas and $1,188,815 for Colonial Gas. The Department has adjusted rate

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231 For Colonial Gas, National Grid's calculation of 6.7 years includes Colonial Gas' merger-related rate plan filing (National Grid Brief at IX.35).

case expense, as set forth above. These adjustments result in an allowable rate case expense recovery of $1,923,223 for Boston Gas-Essex Gas and $1,056,818 for Essex Gas. Further, as explained above, the Department finds that the reasonable level of rate case expense is six years for Boston Gas-Essex Gas and six years for Colonial Gas.

Based on these findings, the Department concludes that the correct level of normalized rate case expense is $320,537 (i.e., $1,923,223 divided by six years) for Boston Gas-Essex Gas and $176,136 for Colonial Gas (i.e., $1,056,818 divided by six years).[232] Accordingly, because National Grid has proposed an amortized rate case expense of $443,866 for Boston Gas-Essex Gas and $240,975 for Colonial Gas, the proposed cost of service of Boston Gas-Essex Gas will be reduced by $123,329 and the proposed cost of service of Colonial Gas will be reduced by $64,839.

Finally, the Department recognizes the extraordinary nature of a base rate proceeding and the associated investment of resources that is required for a petitioner to litigate its case before the Department. We reemphasize, however, our growing concern with the amount of rate case expense associated with base rate proceedings and the need for companies to control these costs. D.P.U. 09-39, at 286; D.P.U. 09-30, at 227; D.P.U. 08-35, at 129; 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. In recent cases, considerable resources have been expended by petitioners seeking to demonstrate that they have sufficiently controlled rate case expense and by adversaries arguing

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232 This represents a decrease of the proposed test year cost of service of $263,933 for Boston Gas-Essex Gas (i.e., $2,187,216 minus $1,923,223), and $132,579 for Colonial Gas (i.e., $1,188,815 minus $1,056,818).

that cost containment was not achieved. Ironically, the time and expense devoted to the examination of a petitioner's efforts to contain costs only serves to drive up rate case expense. Strict adherence to longstanding Department precedent regarding the recovery of rate case expense will mitigate this problem.

As noted above, and stated consistently in prior rate cases, all gas and electric distribution companies must engage in a competitive bidding process for outside rate case services, including legal consultants (see Section X.K.3 above; see, also, D.P.U. 09-39, at 287; D.P.U. 09-30, at 227; D.P.U. 08-35, at 127; D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192). In all but the most unusual of circumstances, it is reasonable to expect that a gas or electric company can comply with the competitive bidding requirement. Nonetheless, significant resources have been spent in recent rate cases litigating a petitioner's justification for its decision to forgo the competitive bidding process.

The competitive bidding and qualification process provides an essential benchmark for the reasonableness of the cost of the services sought. D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Without such a benchmark, it will be difficult for a petitioner to demonstrate that its choice of consultant is both reasonable and cost-effective. Accordingly, we fully expect that in all future gas and electric rate cases, competitive bidding for outside rate case services, including legal services, will be the norm.

The competitive bidding process must be structured and objective, and based on a RFP process that is fair, open, and transparent. See 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 consultants to provide complete bids, and provide for sufficient time to evaluate the bids. The RFPs issued to solicit consultants must clearly identify the scope of work to be performed and the evaluation criteria by which the consultants will be evaluated.

As we have noted before, obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder. However, companies must conduct and document a thorough bid evaluation process. While the Department will not substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve the petitioner's interests, the petitioner must demonstrate that its choice of consultants is both reasonable and cost-effective. See D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153. Again, the best evidence here is contemporaneous documentation of a well-analyzed bid evaluation process. D.P.U. 09-30, at 228.

The Department will continue to closely scrutinize rate case expense and the requirement that a petitioner in a gas or electric rate case engage in a competitive bidding process for its rate case consultants will be enforced. We will disallow recovery of rate case expense where a petitioner fails to adhere to Department precedent and cannot demonstrate that its choice of consultants is reasonable and cost-effective.

Finally, there are clear benefits to shareholders from approval of rate increases and the Department has found that it may be appropriate for shareholders to shoulder a portion of the expense. D.P.U. 08-35, at 135. As one means to demonstrate that rate case expense has been contained, the Department directs gas and electric companies in future rate case filings to consider proposals for some portion of the rate case expense to be borne by shareholders.

L. Uncollectible Expense

1. Distribution-Related Bad Debt

a. Introduction

During the test year, distribution-related bad debt was booked as follows: (1) $19,277,307 to Boston Gas-Essex Gas; and (2) $4,240,255 to Colonial Gas (Exhs. NG-MDL-1, at 39, 75; NG-MDL-2-Boston Gas (Rev. 3) at 7; NG-MDL-2-Colonial Gas (Rev. 3) at 7). National Grid determined the level of bad debt expense to be recovered through base rates by comparing actual distribution related net write-offs to firm billed distribution related revenue for the three years ending December 31, 2009, and deriving the three-year weighted average of net write-offs as a percentage of billed distribution revenue (Exh. NG-MDL-1, at 39). The three-year weighted average percentage was then multiplied by test year normalized firm sales revenues to obtain a bad debt allowance (Exh. NG-MDL-1, at 39).

National Grid calculated a distribution-related bad debt ratio of 2.55 percent for Boston Gas-Essex Gas (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 33). The total adjusted distribution-related revenue for Boston Gas-Essex Gas is $438,971,733 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 33). Thus, the proposed bad debt allowance for Boston Gas-Essex Gas is $11,193,779 ($438,971,733 x 2.55 percent) (Exh. NG-MDL-2-Boston Gas

(Rev. 3) at 33).[233] The bad debt allowance results in a proposed reduction to test year cost of service in the amount of $8,083,528 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7, 33).

National Grid computed a distribution-related bad debt ratio of 1.82 percent for Colonial Gas (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 32). The total adjusted distribution-related revenue for Colonial Gas is $95,997,792 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 32). Thus, the proposed bad debt allowance for Colonial Gas is $1,747,159 ($95,997,792 x 1.82 percent) (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 32).[234] The bad debt allowance results in a proposed reduction to test year cost of service in the amount of $2,493,096 (NG-MDL-2-Colonial Gas (Rev. 3) at 7, 32). No party commented on the proposed adjustments.

b. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt revenues as an expense in cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. The Department has found that the use of the most recent three years of available data is appropriate in the calculation of bad debt. D.P.U. 96-50 (Phase I) at 71. When a company is allowed dollar-for-dollar recovery of bad debt expense associated with supply (commodity related), the appropriate method to calculate bad debt related to distribution is to remove all

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233 National Grid incorrectly calculated the bad debt allowance as $11,211,368, a difference of $17,589 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 33).

234 National Grid incorrectly calculated the bad debt allowance as $1,747,940, a difference of $781 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 32).

revenues relating to supply from the company's bad debt calculations. See D.P.U. 07-71, at 106-109.

The method used by National Grid to calculate its distribution-related bad debt adjustment is consistent with Department precedent. See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. Therefore, the Department approves the application of distribution related bad debt ratios of 2.55 percent for Boston Gas-Essex Gas and 1.82 percent for Colonial Gas, applied to test year distribution revenue (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 7, 33; NG-MDL-2-Colonial (Rev. 3) at 7, 32).

The bad debt ratio of 2.55 percent for Boston Gas-Essex Gas, when applied to the test year normalized distribution revenue of $438,971,733, produces an allowable bad debt expense of $11,193,779. During the test year, Boston Gas-Essex Gas booked $19,277,307 in distribution-related bad debt expense (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 7). Thus, Boston Gas-Essex Gas shall reduce its test year level of bad debt expense related to distribution-related bad debt by the amount of $8,083,528. In addition, in its initial filing, Boston Gas-Essex Gas sought an adjustment for bad debt expense in the amount of $2,023,601 associated with its requested revenue increase (Exh. NG-MDL-2-Boston Gas at 6). During the course of the proceedings, Boston Gas-Essex Gas revised that amount to $1,986,361 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 6). Applying the same 2.55 percent bad debt ratio set forth above to the revenue increase approved in this case, $41,451,838, results in an allowed bad debt expense adjustment in the amount of $1,057,022. Accordingly, the Department calculates a total decrease to the Boston Gas-Essex Gas test year cost of service of $7,026,506 (($8,083,528) + $1,057,022).

The bad debt ratio of 1.82 percent for Colonial Gas, when applied to the test year normalized distribution revenue of $95,997,792, produces an allowable bad debt expense of $1,747,159. During the test year, Colonial Gas booked $4,240,255 in distribution-related bad debt expense (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 7). Thus, Colonial Gas shall reduce its test year level of bad debt expense related to distribution-related bad debt by the amount of $2,493,096. In addition, in its initial filing, Colonial Gas sought an adjustment for bad debt expense in the amount of $488,179 associated with its requested revenue increase (Exh. NG-MDL-2-Colonial Gas at 6). During the course of the proceedings, Colonial Gas revised that amount to $478,804 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 6). Applying the same 1.82 percent bad debt ratio set forth above to the revenue increase approved in this case, $16,475,029, results in an allowed bad debt expense adjustment in the amount of $299,846. Accordingly, the Department calculates a total decrease to the Colonial Gas test year cost of service of $2,193,250 (($2,493,096) + $299,846).

2. Colonial Gas' Collection of Gas-Related Bad Debt

a. Introduction

National Grid proposes that Essex Gas and Colonial Gas recover actual gas-related bad debt write-offs through a CGAC tariff that includes a peak and off-peak bad debt factor (Exhs. NG-AEL-1, at 21-22; NG-AEL-4, at 10-11, 16-17; DPU-1-15). This recovery method is how Boston Gas currently collects its gas-related bad debt write-offs (Exhs. NG-AEL-1 at 21-22; DPU-1-15, Att.; Tr. 10, at 1302). National Grid proposes a single CGAC tariff that will apply the peak and off-peak bad debt factors identically to Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-AEL-1, at 21-22; NG-AEL-4, at 10-11, 16-17; DPU-1-15).

Currently, Essex Gas recovers gas-related bad debt through base rates (Exhs. NG-AEL-5, at 12, 26; DPU-1-15 & Att.; Tr. 10, at 1301-1302). National Grid notes that, in D.T.E. 98-64, the Department approved a gas-cost related bad debt recovery mechanism that allows Colonial Gas to recover through its CGAC, 52 percent and 49 percent of its actual net write-offs for Colonial Gas (Lowell) and Colonial Gas (Cape Cod), respectively (Exh. NG-AEL-1, at 22; Tr. 10, at 1302-1303). According to National Grid, this mechanism did not allow for any changes in the percentage of the gas costs as it relates to the total bill (Exh. NG-AEL-1, at 22). Thus, National Grid proposes to implement for Colonial Gas a gas-related bad debt recovery factor similar to the current Boston Gas mechanism (Exhs. NG-AEL-1 at 22; DPU-1-15 & Att.; Tr. 10, at 1302). No party commented on National Grid's proposal.

b. Analysis and Findings

National Grid proposes to combine the cost recovery for gas-related bad debt into a single CGAC reconciling mechanism applicable to Boston Gas-Essex Gas and Colonial Gas. In D.T.E. 05-27, the Department sought to establish a consistent method by which gas distribution companies could recover gas-related bad debt. Critical to the Department's consideration was the ability of a company to accurately track distribution- and gas-related bad debt writeoffs. D.T.E. 05-27, at 185, 189.

National Grid uses a centralized billing system for Boston Gas, Essex Gas and Colonial Gas (Exhs. DPU-5-2; AG-16-27). Thus, the Companies will be able to track actual monthly writeoffs and segregate the distribution-related and gas-related costs. See D.T.E. 03-40, at 266-267 (noting that Boston Gas was capable of tracking actual monthly write-offs by gas cost and base rates through its billing system). As such, we conclude that National Grid's proposal is consistent with Department precedent. D.T.E. 05-27, at 188-189. Further, we find that National Grid's proposal represents a reasonable and appropriate means by which to eliminate the over- or under-collection of gas-related bad debt. Moreover, consolidating the Boston Gas, Essex Gas, and Colonial Gas bad debt cost recovery efforts into a single CGAC tariff is administratively efficient and consistent with the overall operational integration of the Companies.

Accordingly, the Department approves National Grid's proposal to combine the cost recovery for gas-related bad debt into a single CGAC reconciling mechanism. The Department directs Boston Gas-Essex Gas and Colonial Gas to begin tracking actual gas-related bad debt for the peak period starting November 1, 2010, and to reconcile these expenses in their respective peak 2011-2012 GAF filings. Further, the Department directs Boston Gas-Essex Gas and Colonial Gas to begin tracking gas-related bad debt for the off-peak period starting May 1, 2011, and to reconcile these expenses their respective off-peak 2012 GAF filings.

M. Inflation Allowance

1. Introduction

National Grid originally proposed an inflation adjustment for Boston Gas-Essex Gas of $1,174,723 (Exhs. NG-MDL-1, at 40; NG-MDL-2-Boston Gas at 34). National Grid then revised this amount to $1,153,637 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 34). Regarding Colonial Gas, National Grid originally proposed an inflation adjustment $175,061 (Exhs. NG-MDL-1, at 76; NG-MDL-2-Colonial Gas at 33). National Grid then revised this amount to $171,969 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 33).

To calculate the net inflation allowance, National Grid applied the gross domestic product implicit price deflator ("GDPIPD") from the midpoint of the test year to the midpoint of the rate year, which resulted in a 1.89 percent inflation factor to be applied to both Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-MDL-1, at 40, 76; NG-MDL-2-Boston Gas (Rev. 3) at 34; NG-MDL-2-Colonial Gas (Rev. 3) at 33). National Grid calculated the proposed inflation adjustment for Boston Gas-Essex Gas by multiplying the inflation factor of 1.89 percent by the residual O&M expenses of $61,038,993, thus producing an inflation adjustment of $1,153,637 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 34). Similarly, National Grid calculated the proposed inflation adjustment for Colonial Gas by multiplying the inflation factor of 1.89 percent by the residual O&M expenses of $9,098,876, thus producing an inflation adjustment of $171,969 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 33). No other parties commented on the proposed adjustment.

2. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113. The inflation allowance is intended to adjust approved test year O&M expenses that have not been adjusted for other known changes for inflation where the expenses are heterogenous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. Boston Gas Company, D.P.U. 1720, at 19-21 (1983). The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD 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. 92-250, at 297-298. 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.

National Grid has demonstrated a number of efforts to reduce the Companies' O&M costs. First, all non-union employees were brought under a common health care benefit platform (Exh. AG-1-52). By reducing the number of medical and dental vendors, National Grid was able to stabilize and reduce administrative expenses through economies of scale (Exh. AG-1-52). Second, 80 percent of National Grid's employees are now covered by self-insured health and welfare benefit plans (Exhs. NG-MES-1, at 24; AG-1-52). By self-insuring, National Grid has greater ability to control costs and the costs for the programs are directly linked to the use of benefits (Exhs. NG-MES-1, at 24; AG-1-52). Third, National Grid's medical plans provide extensive health and wellness programs designed to reduce health risks and occurrence of costly diseases, and improve the health status of its employees (Exhs. MES-1, at 24; AG-1-52). Fourth, National Grid's prescription drug benefits are carved out of the medical plans to a single prescription benefits manager, which allows National Grid to leverage a volume discount with a single national vendor and achieve economies of scale (Exh. AG-1-52). Fifth, National Grid has created teams made up of internal nurse practitioners and an outside third party to monitor employee care in its disability benefit program, verify care with treating physicians, find alternative light duty work where feasible, and ensure a rapid return to regular duty as soon as reasonably possible (Exh. MES-1, at 24). Sixth, National Grid's plan is designed to encourage employees to use the services wisely, which should lead to lower health care expenses (Exh. AG-1-52). Seventh, National Grid's medical plans use utilization review practices that review intended hospital admissions, oversee ongoing admissions, require pre-approval for certain services, and provide case management for large claims (Exh. AG-1-52). Finally, National Grid's employees are required to contribute towards the cost of their health care (Exh. AG-1-52).

Further, as noted above in Section X.H, National Grid's proposal to conduct inside service inspections in conjunction with the annual walking surveys is expected to achieve cost savings (Exhs. NG-WJA-2, at 1; DPU-1-3, at 1-2). Additional examples of cost containment efforts include: (1) the deployment of jet compressors and other energy efficiency measures at Massachusetts liquefied natural gas ("LNG") plants which are expected to reduce electricity costs; (2) the outsourcing of the raising of gate boxes to reduce the per-unit cost of maintenance and service activities; and (3) the improved use of human resources and standardization across the system to facilitate more effective training programs and consolidated dispatching to reduce costs (Exhs. NG-WJA-2; DPU-1-3, at 2).

Accordingly, we find that National Grid has implemented cost containment measures. Therefore, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the appropriate period as proposed by National Grid, applied to the Companies' approved level of residual O&M expense, is proper in this case.

If an O&M expense has been adjusted or disallowed for ratemaking purposes, so that the expense is representative of costs to be incurred in the year following new rates, the expense is also removed in its entirety from the inflation allowance. D.T.E. 02-24/25, at 184-185; D.P.U. 01-50, at 19; D.P.U. 88-67 (Phase I) at 141; D.P.U. 87-122, at 82. National Grid has adjusted its test year O&M expense for a variety of items because these expenses have been adjusted for ratemaking purposes (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8). National Grid has also removed Boston Gas-Essex Gas' test year expenses related to Distrigas and local production and storage costs, and Colonial Gas has adjusted its test year O&M expense to remove expenses that are recovered through the CGAC (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 34; NG-MDL-2-Colonial Gas (Rev. 3) at 33). In addition, the Department has adjusted National Grid's expenses related to DriveCam, vehicle leases, and reimbursable employee expenses (see Sections X.U, X.V, X.W below). Therefore, we have removed the Companies' test year expenses associated with these items from their residual O&M expenses. As shown on Table 1 (Boston Gas-Essex Gas) and

Table 1 (Colonial Gas), the proposed inflation allowances for Boston Gas-Essex Gas and Colonial Gas are $1,127,605 and $167,207, respectively. Accordingly, the Department will reduce Boston Gas-Essex Gas' proposed cost of service by $47,118, and reduce Colonial Gas' proposed cost of service by $4,762.

TABLE 1 - Boston Gas/Essex Gas

	Test Year	Normalizing	Adjusted TY
Test Year O&M Expense Per Books	977,854,532	(103,443,910)	874,410,622
Less Gas Cost Expense	740,602,506	(124,786,413)	615,816,093
Operating and Maintenance Subject to Inflation	237,252,026	21,342,503	258,594,529
Less:			
Labor	103,502,137	(698,687)	102,803,450
Health and Hospitalization	12,547,280	(28,971)	12,518,309
Computer Software	2,421,547	(252,496)	2,169,051
DPU Assessment Fees	2,024,290	(1,008,262)	1,016,028
Facilities	5,185,773	(440,863)	4,744,910
Insurance Claims	2,645,778	0	2,645,778
Insurance Premiums	973,123	0	973,123
Inside Inspections	404,719	0	404,719
PBOP	8,186,836	(234,306)	7,952,530
PBOP Deferral Amounts	3,249,032	0	3,249,032
PBOP Transition Obligations	2,711,283	0	2,711,283
Payroll Taxes	3,460,336	(14,418)	3,445,918
Pension	10,990,358	(3,985,288)	7,005,070
Pension Deferral Amortization	4,864,908	0	4,864,908
Postage	2,693,426	149,823	2,843,249
Uncollectibles - Commodity	0	18,930,872	18,930,872
Uncollectibles - Distribuiton	19,277,307	0	19,277,307
Distrigas	325,476	(325,476)	0
Production and Storage Costs	(14,041,647)	14,041,647	0
	171,421,962	26,133,575	197,555,537
O&M Expenses Subject to Inflation per Company	65,830,064	(4,791,072)	61,038,992
LESS: DPU Adjustments			
DriveCam			370,167
Employee Reimbursements			9,789
Promotional Programs			638,175
Advertising Expense			359,214
DPU Sub-total			1,377,345
Residual O&M Expense			59,661,647
Projected Inflation Rate			1.89%
Company Proposal			1,174,723
Inflation Allowance			1,127,605
Difference			47,118

TABLE 1 - Colonial Gas

	Test Year	Normalizing	Adjusted TY
Test Year O&M Expense Per Books	240,878,882	(10,960,196)	229,918,686
Less Gas Cost Expense	193,385,833	(15,737,391)	177,648,442
Operating and Maintenance Subject to Inflation	47,493,049	4,777,195	52,270,244
Less:			
Labor	21,246,886	508,027	21,754,913
Health and Hospitalization	3,103,042	0	3,103,042
Computer Software	550,896	(62,495)	488,401
DPU Assessment Fees	530,389	(264,177)	266,212
Facilities	961,073	0	961,073
Uninsured Claims	318,823	0	318,823
Insurance Premiums	207,210	0	207,210
Inside Inspections	82,644	0	82,644
PBOP	1,890,470	(23,688)	1,866,782
Payroll Taxes	754,313	0	754,313
Pension	6,501,990	(1,004,850)	5,497,140
Postage	790,047	35,229	825,276
Uncollectibles - Commodity	0	2,805,285	2,805,285
Uncollectibles - Distribuiton	4,240,255	0	4,240,255
Costs Recovered Through CGAC	(3,311,863)	3,311,863	0
	37,866,175	5,305,194	43,171,369
O&M Expenses Subject to Inflation per Company	9,626,874	(527,999)	9,098,875
LESS: DPU Adjustments			
DriveCam			70,490
Employee Reimbursements			2,075
Promotional Programs			103,181
Advertising Expense			76,196
DPU Sub-total			251,942
Residual O&M Expense			8,846,933
Projected Inflation Rate			1.89%
Company Proposal			171,969
Inflation Allowance			167,207
Difference			4,762

N. Interest on Customer Deposits

1. Introduction

During the test year, the customer deposit balance for Boston Gas-Essex Gas was $2,849,998 (Exhs. NG-MDL-1, at 41; NG-MDL-2-Boston Gas (Rev. 3) at 35). The customer deposit balance for Colonial Gas was $445,491 (Exhs. NG-MDL-1, at 76; NG-MDL-2-Colonial Gas (Rev. 3) at 34). During the test year, National Grid did not book interest on customer deposits as an O&M expense (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 6; NG-MDL-2-Boston Gas (Rev. 3) at 6).[235] National Grid applied an interest rate payable to customers of 0.96 percent to these totals to arrive at the allowable customer deposit interest of $27,360 for Boston Gas-Essex Gas and $4,277 for Colonial Gas (Exhs. NG-MDL-1, at 41, 76; NG-MDL-2-Boston Gas (Rev. 3) at 35; NG-MDL-2-Colonial Gas (Rev. 3) at 34). No party commented on this issue.

2. Analysis and Findings

The Department's policy is to treat customer deposits as an offset to rate base and to include in cost of service the interest paid on these deposits. D.P.U. 1720, at 90; D.P.U. 1580, at 46-47; D.P.U. 1350, at 20-21. National Grid has included the customer deposit balance of $2,849,998 for Boston Gas-Essex Gas and the customer deposit balance of $445,491 for Colonial Gas as offsets to rate base (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 43; NG-MDL-2-Colonial Gas (Rev. 3) at 42). Consistent with this treatment, the

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235 Pursuant to the USOA-Gas, interest on customer deposits is booked to Account 431, Other Interest Expense, which is typically excluded from the ratemaking process. However, the Department does permit interest on customer deposits to be treated as an expense for ratemaking purposes. D.P.U. 1720, at 90-91.

Department finds it appropriate to include in the costs of service for Boston Gas-Essex Gas and Colonial Gas the appropriate interest expense associated with these deposits. Boston Edison Company, D.P.U. 906, at 24 (1982).

The Department's regulations require utility companies to pay interest on any deposit, represented by cash or cash-equivalent securities that are held for more than six months. 220 C.M.R. § 26.09. The interest rate is equal to the rate paid on two-year U.S. Treasury notes for the preceding twelve months ending December 31st of each year, as reported by the Federal Reserve System's monthly bulletin. 220 C.M.R. § 26.09. The interest rate on two-year U.S. Treasury notes for the year ending December 31, 2009, was 0.96 percent (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 35; NG-MDL-2-Colonial Gas (Rev. 3) at 34; NG-MDL-6-Boston Gas WP 14, citing Federal Reserve Statistical Release H.15, "Selected Interest Rates"). Therefore, the Department will apply this interest rate to the test year-end balance of customer deposits, producing an interest expense for Boston Gas-Essex Gas of $27,360 and an interest expense rate for Colonial Gas of $4,227 (Exhs. NG-MDL-1, at 41, 76; NG-MDL-2-Boston Gas (Rev. 3) at 35); NG-MDL-2-Colonial Gas (Rev. 3) at 34). Accordingly, the test year cost of service of Boston Gas-Essex Gas will be increased by $27,360 and the test year cost of service of Colonial Gas will be increased by $4,277.

O. Depreciation Expense

1. Introduction

During the test year, National Grid booked depreciation expense as follows: (1) $98,557,438 for Boston Gas-Essex Gas; and (2) $20,072,249 for Colonial Gas

(Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 36; NG-MDL-2-Colonial (Rev. 3) at 35). National Grid proposes to decrease depreciation expense by $8,282,325 for Boston Gas-Essex Gas and by $503,426 for Colonial Gas based on the application of new accrual rates to the pro forma plant in service (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 36; NG-MDL-2-Colonial (Rev. 3) at 35). The composite accrual rates of 4.44 percent for Boston Gas and 3.44 percent for Colonial Gas result in annual depreciation expense amounts of $90,275,113 and $19,568,823, respectively (Exhs. NG-MDL-1, at 41, 77; NG-PMN-2, at 15; NG-MDL-2-Boston Gas (Rev. 3) at 36; NG-MDL-2-Colonial (Rev. 3) at 35).

National Grid's depreciation studies use the overall straight-line method, broad group procedure, and average remaining-life technique, an approach wherein the cost of plant, less depreciation and net salvage, is recovered over the estimated remaining life of the property in each plant account (Exh. NG-PMN-2, at 3). The depreciation studies were based on plant data as of December 31, 2008 (Exh. NG-PMN-2, at 3). Historical plant data were analyzed using the simulated plant record balances ("SPR BAL") life analysis method, which can be performed whenever there is an adequate volume and frequency of additions and retirements (Exh. NG-PMN-2, at 7). The procedure identifies the empirical survivor curves ("Iowa curves")[236] that best simulate the actual ending balances in a specified band of years to produce an average service life ("ASL") for the asset under study (Exh. NG-PMN-2, at 7).

[236] Iowa curves are frequency distribution curves 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 (Exh. NG-PMN-2, at 8). Initially, 18 curve types were published in 1935, and four additional survivor curves were identified in 1957. D.T.E. 06-40, at 67 n.44.

Using the ASL data, considerations of plant additions, infrastructure improvements, and engineering judgment, National Grid calculated the remaining life of plant accounts (Exh. NG-PMN-2, at 13).

National Grid also developed net salvage factors for plant accounts (Exh. NG-PMN-2, at 13). The calculated net salvage factors were used in the derivation of each of the proposed accrual rates presented in the depreciation studies (Exh. NG-PMN-2, at 13). Application of the resulting accrual rates to plant in service as of December 31, 2008, resulted in composite accrual rates of 4.44 percent for Boston Gas-Essex Gas and 3.44 percent for Colonial Gas (Exh. NG-PMN-2, at 15).

2. Positions of the Parties

a. Attorney General

i. Overview

The Attorney General argues that National Grid made several errors in performing the depreciation studies that caused the depreciation accrual rates for certain plant accounts to be grossly overstated (Attorney General Brief at 147). Specifically, the Attorney General contends errors exist in the proposed accrual rates for Accounts 367 and 380 for Boston Gas, Essex Gas, and Colonial Gas (Attorney General Brief at 147-155; Attorney General Reply Brief at 70). For example, the Attorney General maintains that National Grid's proposed salvage factors are based on a selective "cherry picking" of data merely intended to bolster the Companies' claims in the face of evidence to the contrary (Attorney General Reply Brief at 70). The Attorney General's arguments regarding specific accrual rates are detailed below.

ii. Account 367 – Distribution Mains – Boston Gas

The Attorney General challenges National Grid's ASL recommendation of 71 years for Boston Gas' Account 367, arguing that the life analyses provided by the depreciation studies suggest an ASL of at least 100 years (Attorney General Brief at 148). The Attorney General contends that National Grid should recalculate the depreciation accrual rate for Account 367 and change the ASL to a minimum of 100 years as indicated by the study (Attorney General Brief at 148).

iii. Account 380 – Services – Boston Gas

The Attorney General challenges National Grid's ASL recommendation of 43 years for Boston Gas' Account 380, arguing that the life analyses provided by the depreciation studies suggest an ASL of at least 45 years (Attorney General Brief at 150-151). The Attorney General contends that National Grid should recalculate the depreciation accrual rate for Account 380 and change the ASL to at least 50 years as indicated by the study (Attorney General Brief at 151).

iv. Account 367 – Distribution Mains – Essex Gas

The Attorney General challenges National Grid's ASL recommendation of 56 years for Essex Gas' Account 367, contending that the life analyses provided by the depreciation studies support an ASL of at least 90 years (Attorney General Brief at 151-152). The Attorney General contends that National Grid should recalculate the depreciation accrual rate for Account 367 and change the ASL to a minimum of 90 years (Attorney General Brief at 152).

The Attorney General also objects to National Grid's proposed net salvage value of negative 65 percent for Account 367, stating that the analyses suggest a net salvage value of negative 36.4 percent (Attorney General Brief at 152). The Attorney General asserts that the net salvage value for Essex Gas' mains account should be increased to negative 40 percent to better reflect the results of the depreciation studies (Attorney General Brief at 152; Attorney General Reply Brief at 70).

v. Account 380 – Services – Essex Gas

The Attorney General challenges National Grid's recommended ASL of 44 years for Essex Gas' Account 380, claiming that the analyses overwhelmingly support an ASL of at least 50 years (Attorney General Brief at 153). The Attorney General contends that National Grid should recalculate the depreciation accrual rate for Account 380 and change the ASL to at least 50 years (Attorney General Brief at 153).

vi. Account 367 – Distribution Mains – Colonial Gas (Cape Cod)

The Attorney General challenges National Grid's proposal to make no change to the net salvage value of negative 50 percent for Colonial Gas (Cape Cod) Account 367 (Attorney General Brief at 153-154). The Attorney General argues that the analyses provided by National Grid indicate a net salvage value of negative 26.4 percent (Attorney General Brief at 154). The Attorney General contends that the net salvage value for this account should be increased to negative 38 percent (Attorney General Brief at 154).

vii. Account 380 – Services – Colonial Gas (Cape Cod)

The Attorney General challenges National Grid's decision to not change the net salvage value for services of negative 60 percent for Colonial Gas (Cape Cod) (Attorney General Brief at 154). The Attorney General claims the analyses in the depreciation study indicates a net salvage value of negative 34.3 percent (Attorney General Brief at 154). The Attorney General contends that the net salvage value for services for Colonial Gas (Cape Cod) should be increased to negative 47 percent (Attorney General Brief at 154).

viii. Account 367 – Distribution Mains – Colonial Gas (Lowell)

The Attorney General challenges National Grid's decision to maintain the net salvage value of negative 50 percent calculated in the previous depreciation study (Attorney General Brief at 155). The Attorney General contends that the analyses support a net salvage value of negative 21.3 percent (Attorney General Brief at 155). The Attorney General recommends that the net salvage value for mains for Colonial Gas (Lowell) be increased to negative 35 percent (Attorney General Brief at 155; Attorney General Reply Brief at 70).

b. National Grid

i. Overview

National Grid submits that when conducting a depreciation study, the ASL indications resulting from the statistical output of the SPR-BAL analysis must be evaluated in the context of statistical significance and, once the appropriate Iowa curves and ASLs are selected, the results must be evaluated based on input from company personnel, the character of the depreciable assets, knowledge gained during property inspections, and engineering knowledge and judgment (National Grid Brief at X.2-3; National Grid Reply Brief at 122). National Grid claims that the assertions made by the Attorney General with regard to the ASL and net salvage values are based on a fundamental misunderstanding of the elements underlying a comprehensive depreciation study and how the various aspects of such studies must be integrated and interpreted to arrive at proper depreciation accrual rates (National Grid Brief at X.3). National Grid contends that in challenging its studies, the Attorney General focuses only on the output of the SPR-BAL statistical analysis and ignores the additional aspects of the study that enabled National Grid to arrive at proposed its ASL and net salvage values (National Grid Brief at X.4).

Furthermore, National Grid argues that its proposed accrual rates take into consideration the Companies' TIRF proposal and their intent to significantly increase expenditures related to the replacement of bare steel and cast iron mains and service (National Grid Reply Brief at 124). The Companies contend that when utilities engage in significant retirements, costs of removal increase significantly and quickly (National Grid Reply Brief at 124). Under these circumstances, National Grid maintains that its proposed salvage factors for Essex Gas' and Colonial Gas' mains are both conservative and fully supported by its analysis and industry experience (National Grid Reply Brief at 124).

Based on the above, National Grid argues that its proposed accrual rates should be accepted (National Grid Brief at X.13). National Grid's arguments concerning the specific accounts challenged by the Attorney General are discussed below.

ii. Account 367 – Distribution Mains – Boston Gas

National Grid contends that, with regard to Account 367 for Boston Gas, the Attorney General references the raw data output from the SPR-BAL statistical analysis and makes her recommendations based solely on the mean value of best fitting lives (National Grid Brief at X.4-7). National Grid argues that a proper analysis of results requires an evaluation of statistical significance (measured by a conformance index, retirement index, and cycle index), as well as judgments based on the other important elements of the study (National Grid Brief at X.7). The Companies maintain that because they applied this process, the resulting ASL and salvage factor for this account is reliable and reasonable (National Grid Brief at X.9).

iii. Account 380 – Services – Boston Gas

National Grid asserts that the Attorney General's recommendation for changing the ASL for Boston Gas Account 380 suffers from the same deficiencies, errors, and misunderstanding of the SPR-BAL analysis discussed above for Account 367 (National Grid Brief at X.9). The Companies claim the Attorney General has inappropriately relied on the mean value of the best fitting lives and misapplied that number as if it represented the appropriate ASL for the class of asset being reviewed (National Grid Brief at X.9). National Grid states that the Attorney General's reliance on a mean value fails to filter out values and curves that are not statistically reliable and does not take into account any engineering judgment (National Grid Brief at X.9). Moreover, National Grid argues that the Attorney General's proposed salvage factor for this account demonstrates that the Attorney General relies on selective criteria in that, whenever her preferred salvage analysis approach results in a higher negative net salvage factor, she simply ignores the account (National Grid Reply Brief at 125). Therefore, National Grid contends that the Attorney General's proposed ASL for Account 380 should be rejected (National Grid Brief at X.13).

iv. Account 367 – Distribution Mains – Essex Gas

National Grid asserts that the ASL suggested by the Attorney General for Essex Gas Account 367 should be rejected as it results from a misapplication of an inappropriate portion of the SPR-BAL statistical analysis (National Grid Brief at X.9). Regarding the analysis for this account, National Grid contends that the Attorney General only relied upon the mean value of the best fitting lives and failed to make the additional assessments necessary to arrive at a proper ASL (National Grid Brief at X.9).

Further, National Grid argues that the net salvage value recommended by the Attorney General regarding Account 367 for Essex Gas should be rejected (National Grid Brief at X.10-13). National Grid contends that the Attorney General's argument refers only to the schedules that provide the raw data regarding historical salvage value and costs to retire, resulting in a misapplication of historical data (National Grid Brief at X.11). National Grid further contends that simply taking an average, without any analysis of the data, is an inappropriate basis on which to form a conclusion regarding the level of retirement costs a company is likely to experience in the future (National Grid Brief at X.12). The Companies defend their proposed salvage factor for this account as fully supported by the evidence (National Grid Reply Brief at 124).

v. Account 380 – Services – Essex Gas

National Grid argues that the Attorney General's recommendation for changing the ASL for Essex Gas Account 380 suffers from the same deficiencies, errors, and misunderstanding of the SPR-BAL analysis discussed previously for Account 367 (National Grid Brief at X.9). National Grid claims the Attorney General has inappropriately relied on the mean value of the best fitting lives and misapplied that number as if it represented the appropriate ASL for the class of asset being reviewed (National Grid Brief at X.9). National Grid states that the mean value fails to filter out values and curves that are not statistically reliable, and does not take into account any engineering judgment (National Grid Brief at X.9). Therefore, National Grid contends that the Attorney General's proposed ASL for Account 380 for Essex Gas should be rejected (National Grid Brief at X.13).

vi. Account 367 – Distribution Mains – Colonial Gas (Cape Cod)

National Grid submits that its recommendation to continue to use a negative 50 percent net salvage value for Account 367 for Colonial Gas (Cape Cod) is fully supported by the data (National Grid Brief at X.12; National Grid Reply Brief at 123-124). National Grid contends that it was very conservative with its net salvage recommendations, considering the data indicate an escalation in the costs to retire mains in recent years, with the cost to retire in 2008 of negative 68.2 percent (National Grid Brief at X.12; National Grid Reply Brief at 123). Therefore, National Grid asserts that the Attorney General's recommended net salvage value for Account 367 for Colonial Gas should be rejected (National Grid Brief at X.13).

vii. Account 380 – Services – Colonial Gas (Cape Cod)

National Grid submits that its recommendation to continue to use a negative 60 percent net salvage value for Account 380 for Colonial Gas (Cape Cod) is fully supported by the data (National Grid Brief at X.13; National Grid Reply Brief at 122-123). National Grid contends there is uncontroverted evidence that the cost of retiring mains and services has continued to escalate in recent years (National Grid Brief at X.13). Based upon its review of all of the available retirement data, including an evaluation of trends, and the witness's experience, National Grid contends that its proposal not to change the net salvage value currently used for Colonial Gas (Cape Cod) Account 380 is appropriate and conservative (National Grid Brief at X.13; National Grid Reply Brief at 122-123). Therefore, National Grid asserts that the Attorney General's recommended net salvage value for Account 380 for Colonial Gas (Cape Cod) should be rejected (National Grid Brief at X.13).

viii. Account 367 – Distribution Mains – Colonial Gas (Lowell)

National Grid argues that there is no basis to change the current negative 50 percent level of net salvage for Colonial Gas (Lowell) Account 367 (National Grid Brief at X.13; National Grid Reply Brief at 123). National Grid contends there is uncontroverted evidence that the cost of retiring mains and services has continued to escalate in recent years and, therefore, its proposal not to change the net salvage value currently used for Colonial Gas (Lowell) Account 367 is appropriate (National Grid Brief at X.13; National Grid Reply Brief at 123). Therefore, National Grid asserts that the Attorney General's recommended net salvage value for Account 367 for Colonial Gas (Lowell) should be rejected (National Grid Brief at X.13).

3. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 110 (2009); Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 75 (1998); Boston Gas Company, D.P.U. 96-50 (Phase I) at 104 (1996); Milford Water Company, D.P.U. 84-135, at 23 (1985). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. See The Berkshire Gas Company, D.P.U. 92-210, at 71 (1993); Bay State Gas Company, D.P.U. 92-111, at 121 (1992); The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982). The Department has held that when a company reaches a conclusion about a depreciation study which is at variance with the 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. 08-27, at 110; Cambridge Electric Light Company, D.P.U. 92-250, at 64 (1993); Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 54-55 (1991). It is also necessary to go beyond the numbers presented in a depreciation study and consider the underlying physical assets. D.P.U. 08-27, at 110; D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982).

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.P.U. 08-27, at 110; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132

(2002). Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable. Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific accounts' balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); Massachusetts Electric Company, D.P.U. 200, at 20-21 (1980); 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 its statistical analyses but will consider expert testimony and evidence to the contrary and expect sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase One) at 54. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

b. Account by Account Analysis

i. Account 367 – Distribution Mains – Boston Gas

The current accrual rate for this account is 2.49 percent (Exh. NG-PMN-2, Att. PMN-2, at 37). National Grid proposes to use a 71-year S 2.0 curve and a salvage factor of negative 65 percent for this account, resulting in an increase in the accrual rate to 2.76 percent (Exh. NG-PMN-2, Att. PMN-2, at 33). The Attorney General proposes increasing the ASL to at least 100 years, in recognition of the life analyses provided by National Grid, which demonstrate mean values of 100 years or more (Attorney General Brief at 148).

While the Attorney General's proposed ASL is based on her review of the SPR-BAL data output, she has not taken into consideration the other elements of statistical review, such as conformance indices, retirement indices, and cycle indices, as well as the impacts of capital replacement efforts on future analyses (Attorney General Brief at 148). In contrast, National Grid has considered all of this data in arriving at its proposed ASL (Tr. 9, at 1183, 1187, 1196-1199). The Department finds that National Grid has properly interpreted the data and exercised reasoned judgment in its selection of the proposed ASL. Therefore, the Department accepts the proposed accrual rate for Account 367.

ii. Account 380 – Services – Boston Gas

The current accrual rate for this account is 8.63 percent (Exh. NG-PMN-2, Att. PMN-2, at 37). National Grid proposes to use a 43-year S 2.0 curve and a salvage factor of negative 175 percent for this account, resulting in a decrease in the accrual rate to 7.2 percent (Exh. NG-PMN-Boston Gas, Att. 2, at 33). The Attorney General proposes increasing the ASL to at least 50 years, in recognition of the life analyses provided by National Grid, which demonstrate mean values of 50 years or more (Attorney General Brief at 151).

While the Attorney General's proposed ASL is based on her review of the SPR-BAL data output, she has not taken into consideration the other elements of statistical review, as well as the impacts of capital replacement efforts on future analyses (Attorney General Brief at 150-151). National Grid's analyses for this account produce statistically significant results indicating an increase from the previously approved ASL of 40 years (Exh. NG-PMN-Boston Gas WP 6, at 17, 18). National Grid has also considered the effects of the current replacement program for services in determining the modest increase to the ASL for Account 380 (Exh. NG-PMN-2, Att. PMN-2, at 26-27; Tr. 9, at 1182-1183). Based on the statistical results and interpretations of the effects of capital replacement programs, the Department finds that National Grid has properly interpreted the data and exercised reasoned judgment in its selection of the proposed ASL. Therefore, the Department accepts the proposed accrual rate for Account 380.

iii. Account 367 – Distribution Mains – Essex Gas

The current accrual rate for this account is 3.7 percent (Exh. NG-PMN-2, Att. PMN-3, at 37). National Grid proposes to use a 56-year L 4.0 curve and a salvage factor of negative 65 percent for this account, resulting in a decrease in the accrual rate to 2.96 percent (Exh. NG-PMN-2, Att. PMN-3, at 32). The Attorney General proposes increasing the ASL to at least 90 years, in recognition of the life analyses provided by National Grid, which demonstrate mean values of 90 years or more (Attorney General Brief at 152).

While the Attorney General's proposed ASL is based on her review of the SPR-BAL data output, she has not taken into consideration the other elements of statistical review, such as conformance indices, retirement indices, and cycle indices as well as the impacts of capital replacement efforts on future analyses (Attorney General Brief at 151-152). The SPR-BAL results show low retirement and cycle index values for greater ASLs, while life curves with ASLs of 55.6 are much more statistically significant (Exh. NG-PMN-Essex Gas WP 7, at 7-8). Given the SPR-BAL results and consideration regarding the capital replacement program, the Department finds that National Grid has properly interpreted the data and exercised reasoned judgment in proposing to increase the current ASL from 46 years to 56 years.

The Attorney General also proposes increasing the net salvage value to negative 40 percent, rather than the negative 65 percent recommended by National Grid, referring to analysis results that suggest a net salvage of negative 36.4 percent (Attorney General Brief at 152). The Attorney General's suggested net salvage is merely the average of the value provided by the raw data output and the previously approved net salvage value, and is not based on any analysis of the underlying data (Attorney General Brief at 152).

The retirement experience associated with distribution mains indicates an escalation in the costs to retire in recent years, with Essex Gas experiencing a negative 387.6 percent cost (Exh. NG-PMN-Essex Gas WP 2, at 982). Based on the data provided, the Department finds National Grid's proposed net salvage to be conservative and appropriate. The Department finds that National Grid has properly interpreted the data and exercised reasoned judgment in its selection of the proposed ASL and net salvage factor. Therefore, the Department accepts the proposed accrual rate for Account 367.

iv. Account 380 – Services – Essex Gas

The current accrual rate for this account is 3.7 percent (Exh. NG-PMN-2, Att. PMN-3, at 37). National Grid proposes to use a 44-year S 1.0 curve and a salvage factor of negative 80 percent for this account, resulting in an increase in the accrual rate to 5.08 percent (Exh. NG-PMN-2, Att. PMN-3, at 32). The Attorney General proposes increasing the ASL to at least 50 years, in recognition of the life analyses provided by National Grid, which demonstrate mean values of 50 years or more (Attorney General Brief at 153).

While the Attorney General's proposed ASL is based on her review of the SPR-BAL data output, she has not taken into consideration the other elements of statistical review, such as conformance indices, retirement indices, and cycle indices as well as the impacts of capital replacement efforts on future analyses (Attorney General Brief at 153). National Grid's analyses for this account produce low retirement and cycle index values for most life-curve combinations, with more statistically significant results for curves with lower ASLs (Exh. NG-PMN-Essex Gas WP 7, at 11-12). Based on these statistical results and consideration for the effects of the capital replacement program, the Department finds that National Grid has properly interpreted the data and exercised reasoned judgment in its selection of the proposed ASL. Therefore, the Department accepts the proposed accrual rate for Account 380.

v. Account 367 – Distribution Mains – Colonial Gas (Cape Cod Division)

The current accrual rate for this account is 3.06 percent (Exh. NG-PMN-2, Att. PMN-5, at 50). National Grid proposes to use a 46-year S 5.0 curve and a salvage factor of negative 50 percent for this account, resulting in an increase in the accrual rate to

3.31 percent (Exh. NG-PMN-2, Att. PMN-5, at 45). The Attorney General proposes increasing the net salvage factor to negative 38 percent, claiming that the analyses indicate a net salvage of negative 26.4 percent (Attorney General Brief at 154).

The Attorney General's suggested net salvage is the average of the value provided by the raw data output and the previously approved net salvage value, and lacks any analysis of the underlying data (Attorney General Brief at 153-154). The retirement experience associated with distribution mains indicates an escalation in the costs to retire in recent years, with Colonial Gas (Cape Cod) experiencing a negative 68.2 percent cost to retire assets in Account 367 for 2008 (Exh. NG-PMN-Colonial Gas (Cape Cod) WP 2, at 626). Based on the data provided, the Department finds National Grid's proposed net salvage to be conservative and appropriate. Therefore, the Department accepts the proposed accrual rate for Account 367.

vi. Account 380 – Services – Colonial Gas (Cape Cod Division)

The current accrual rate for this account is 4.71 percent (Exh. NG-PMN-2, Att. PMN-5, at 50). National Grid proposes to use a 40-year S 3.0 curve and a salvage factor of negative 60 percent for this account, resulting in a decrease in the accrual rate to 3.65 percent (Exh. NG-PMN-2, Att. PMN-5, at 45). The Attorney General proposes increasing the net salvage factor to negative 47 percent, claiming the analyses indicate a net salvage of negative 34.3 percent (Attorney General Brief at 154).

The Attorney General's suggested net salvage is the average of the value provided by the raw data output and the previously approved net salvage value, and lacks any analysis of the underlying data (Attorney General Brief at 154). National Grid's cost of retirement experience suggests that its recommendation to leave the previously accepted net salvage factor of negative 60 percent is appropriate (Exh. NG-PMN-Colonial Gas (Cape Cod) WP 2, at 629-630). Based on the data provided, the Department finds National Grid's proposed net salvage to be conservative and appropriate. Therefore, the Department accepts the proposed accrual rate for Account 380.

vii. Account 367 – Distribution Mains – Colonial Gas (Lowell Division)

The current accrual rate for this account is 2.56 percent (Exh. NG-PMN-2, Att. PMN-6, at 41). National Grid proposes to use a 60-year S 3.0 curve and a salvage factor of negative 50 percent for this account, resulting in an increase in the accrual rate to 4.01 percent (Exh. NG-PMN-2, Att. PMN-5, at 36). The Attorney General proposes increasing the net salvage factor to negative 35 percent, claiming the analyses indicate a net salvage of negative 21.3 percent (Attorney General Brief at 155).

The Attorney General's suggested net salvage is the average of the value provided by the raw data output and the previously approved net salvage value, and lacks any analysis of the underlying data (Attorney General Brief at 155). National Grid's cost of retirement experience shows that Colonial Gas (Lowell) experienced a negative 54.7 percent cost to retire mains in 2008 (Exh. NG-PMN-Colonial Gas (Lowell) WP 10, at 956). Based on the data provided, the Department finds that National Grid's recommendation to leave the previously accepted net salvage factor of negative 60 percent is appropriate. Therefore, the Department accepts the proposed accrual rate for Account 367.

c. Conclusion

Based on the analysis above, the Department finds that National Grid has appropriately calculated the depreciation expense for Boston Gas, Essex Gas, and Colonial Gas. Therefore, the Department approves the proposed depreciation accrual rates. Application of these accrual rates to National Grid's depreciable plant balances included in rate base produces a depreciation expense of $90,275,173 for Boston Gas-Essex Gas, and a depreciation expense of $19,568,823 for Colonial Gas. As noted in Section X.O, above, the Department has excluded from Boston Gas-Essex Gas' proposed cost of service $820,748 in depreciation expense associated with Essex Gas' plant additions made between 1996 and 1998. Therefore, the Department will include reduce Boston Gas-Essex Gas' proposed depreciation expense by $820,748, and accept the proposed depreciation expense for Colonial Gas.

P. Colonial Gas' Merger Savings Allowance

1. National Grid's Proposal

a. Overview

On August 31, 1999, Colonial Gas became a wholly-owned subsidiary of Eastern Enterprises ("Eastern"). See Eastern Enterprises-Colonial Gas Company Merger, D.T.E. 98-128 (1999) ("Eastern-Colonial Gas merger"). As part of that acquisition, the Department approved an Agreement and Plan of Reorganization between Colonial Gas and Eastern. D.T.E. 98-128, at 3-4, 106. In addition, the Department approved a merger-related rate plan ("Rate Plan") for Colonial Gas that: (1) commenced a ten-year distribution rate freeze ending on July 15, 2009; (2) provided for the recovery of merger-related costs during the ten-year rate freeze through retention of merger savings; and (3) provided for the recovery of the merger-related costs following the expiration of the ten-year rate freeze based on a tracking mechanism to be used for determining the amount of merger-related savings available to offset these merger-related costs. D.T.E. 98-128, at 8-12, 16 n.19). Under the terms of the Rate Plan, for 30 years following the expiration of the rate freeze, Colonial Gas is allowed recovery of up to $12.3 million annually of merger-related costs through distribution rates (i.e., a "merger savings allowance"), so long as it can demonstrate merger-related savings realized during the ten-year rate freeze to offset the amount sought for recovery through rates.[237] D.T.E. 98-128, at 8-12, 16 n.19).

To the extent that savings in excess of $12.3 million annually are demonstrated at the conclusion of the ten-year rate freeze period, rates would be established to flow savings in excess of that amount to customers. D.T.E. 98-128, at 90-92, 96. If, on the other hand, Eastern and Colonial Gas demonstrate annual savings of less than $12.3 million, then Colonial Gas could only recover annually that portion of the merger cost that can be offset by demonstrated savings from the merger. D.P.U. 98-128, at 96.

National Grid proposes a merger savings allowance of $11,080,351 based on the Rate Plan approved in D.T.E. 98-128 (Exhs. NG-MDL-1, at 90-91, 98; NG-MDL-6-Colonial Gas

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[237] In D.T.E. 98-28, at 92-96, the Department found that the annual amount of merger related costs, amortized over a 40-year period, was $12.3 million. These costs included: (1) the payment of an acquisition premium (also referred to as "goodwill") of $199.2 million, or $8.2 million per year on a pre-tax basis over a 40-year amortization period; and (2) $4.1 million in annual interest expense associated with a $144 million cash investment used in paying for the acquisition. D.T.E. 98-128, at 91-92, 96-100.

(Rev. 3) at 1).[238] Accordingly, National Grid included $11,080,351 as an operations and maintenance ("O&M") expense in its cost of service filing (Exh. NG-MDL-2-Colonial (Rev. 3) at 7, 29).

b. Calculation of Merger Savings

In determining its proposed merger savings allowance, National Grid states that it used the tracking mechanism approved in D.T.E. 98-128 (Exh. NG-MDL-1, at 90-91). National Grid submits that such a tracking mechanism calculates Colonial Gas' revenue requirement at the end of the ten-year rate freeze had Colonial Gas continued to operate on a stand-alone basis (Exh. NG-MDL-1, at 94, citing D.T.E. 98-128, at 9). Further, National Grid states that, pursuant to D.T.E. 98-128, at the end of the ten-year rate freeze Colonial Gas' stand-alone revenue requirement would be compared to Colonial Gas' actual revenue requirement to determine the amount of savings achieved during the ten-year rate freeze (Exh. NG-MDL-1, at 94). National Grid states that Colonial Gas' stand-alone revenue requirement consists of two components: (1) a cast-off revenue requirement as determined in D.T.E. 98-128; and (2) an escalation factor to adjust the cast-off revenue requirement to account for inflation,

238 According to National Grid, this amount is equal to demonstrated merger savings of $10,874,857 grossed up for an uncollectible factor of 1.82 percent ($11,080,351 = $10,874,857/(1-0.0182)) (Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 1). Colonial Gas' net cost of service, before the application of this merger savings allowance, is $113,073,750, which is equal to Colonial Gas' proposed rate year cost of service of $124,154,101 minus the merger savings allowance of $11,080,351 (Exhs. NG-MDL-2-Colonial (Rev 3) at 6; NG-MDL-6-Colonial (Rev 3) at 1).

productivity, and throughput growth throughout the rate-freeze period (Exh. NG-MDL-1, at 94-95, citing D.T.E. 98-128, at 10, 57; see also, D.T.E. 98-128, at 12).[239]

National Grid uses a cast-off distribution revenue requirement of $90,816,041 based on the compliance filing approved in D.T.E. 98-128 (Exhs. NG-MDL-1, at 96; NG-MDL-6-Colonial Gas (Rev. 3) at 1; NG-MDL-7-Colonial Gas at 3; DPU-8-6). This revenue requirement consists of $41,097,702 for Colonial Gas (Cape Cod) and $49,720,339 for Colonial Gas (Lowell) (Exhs. NG-MDL-6-Colonial Gas (Rev. 3) at 1).

National Grid sets the factor used to escalate Colonial Gas' cast-off distribution revenue requirement equal to the gross domestic product price index ("GDP-PI") to measure inflation minus a productivity offset (Exh. NG-MDL-1, at 95). National Grid submits that this formula was established by the Department in D.T.E. 98-128 (Exh. NG-MDL-1, at 95, citing D.T.E. 98-128, at 57). National Grid explains that it calculated the inflation factor as the four-quarter average of the GDP-PI (Exhs. NG-MDL-1, at 96; NG-MDL-6-Colonial Gas (Rev. 3) at 3; DPU-8-1). National Grid states that, because the rate year in the instant docket extends to the mid-point of 2011, the 2011 inflation rate is prorated by dividing the 2011 inflation rate in half (Exhs. NG-MDL-6-Colonial Gas (Rev. 3) at 1; DPU-8-3).[240]

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239 To determine the stand-alone revenue requirement of Colonial Gas at end of the ten-year rate freeze, National Grid applied (1) the actual GDP-PI experienced each year during the ten-year rate freeze, and (2) the productivity offset used in the Boston Gas PBR plan in each of those years, to the cast-off revenue requirement determined in D.T.E. 98-128, adjusted for growth in firm throughput. (Tr. 3, at 270-272, citing D.T.E. 98-128, at 11-12).

240 The same method of proration was performed for the 2000 rate year in D.T.E. 98-128 (Exhs. NG-MDL-6-Colonial Gas (Rev. 3) at 3; DPU-8-3).

Regarding the productivity offset, National Grid used a productivity offset of 0.5 percent from January 2000 through October 2003 (Exhs. NG-MDL-1, at 97; NG-MDL-6-Colonial Gas (Rev. 3) at 3; DPU-8-1).[241] For the period from November 2003 through December 2009, National Grid used a productivity offset of 0.41 percent (Exhs. NG-MDL-1, at 97; NG-MDL-6-Colonial Gas (Rev. 3) at 3).[242]

Using the applicable annual inflation rate less productivity offsets, National Grid escalated these cast-off distribution revenue requirements for each calendar year in the period beginning July 1, 2000, through the mid-point of the 2011 rate year in this proceeding (Exhs. NG-MDL-1, at 96; NG-MDL-6-Colonial Gas (Rev. 3) at 1).[243] These calculations resulted in a total escalated revenue requirement through the mid-point of 2011 equal to $109,979,289,

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241 National Grid indicated that the basis for the 0.5 percent productivity offset is the Department's Order in Boston Gas Company, D.T.E. 96-50-D (Phase I) (2001) (Exhs. NG-MDL-1, at 97; DPU-8-5). However, D.T.E. 96-50-D (Phase I) (2001), which reduced the initially determined accumulated inefficiency factor from 1.0 percent to 0.5 percent, resulted in a productivity offset of 1.0 percent (1.0 = 0.1 – 0.1 + 0.5 + 0.5), not 0.5 percent (Exh. DPU-8-5, Att. C at 5). Nevertheless, National Grid's filed schedules used a productivity offset of 0.5 percent (Exh. NG-MDL-6-Colonial (Rev. 3) at 3; see Exhs. NG-MDL-6-Colonial at 3; NG-MDL-Colonial (Rev. 1) at 3).

242 The Department established a new productivity offset for Boston Gas, effective November 1, 2003, in D.T.E. 03-40.

243 In its initial filing, National Grid escalated the cast-off revenue requirements for each calendar year, starting with 2000 through the mid-point of the 2011 rate year in this proceeding, including a partial year calculation for the period August 1, 1999 through December 31, 1999 to account for the period following the Department's Order in D.T.E. 98-128 issued on July 15, 1999 (Exhs. NG-MDL-1, at 96; NG-MDL-6-Colonial Gas at 1; DPU-8-3; NG-MDL-Rebuttal-1, at 13, citing D.T.E. 98-128, at 34-35).

consisting of $49,767,376 for Colonial Gas (Cape Cod) and $60,211,913 for Colonial Gas (Lowell) (Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 1).

National Grid then increased these escalated revenue requirements by 12.7 percent to account for increased throughput, resulting in an adjusted total revenue requirement of $123,948,607 (Exhs. NG-MDL-1, at 97; NG-MDL-6-Colonial Gas (Rev. 3) at 1). National Grid calculated this 12.7 percent growth rate by comparing the 1997 weather normalized firm throughput to the 2009 weather normalized firm throughput, with 1997 representing the test year in D.T.E. 98-128 and 2009 representing the test year in the instant proceeding (Exhs. NG-MDL-1, at 97; NG-MDL-6-Colonial Gas (Rev. 3) at 2; DPU-8-2).

National Grid submits that because the proposed revenue requirement for Colonial Gas in this proceeding, net of the merger savings allowance, is equal to $113,073,750, the application of the tracking mechanism demonstrates that $10,874,857 ($123,948,607 - $113,073,750) in merger savings was achieved (Exh. NG-MDL-6-Colonial Gas (Rev 3) at 1).[244] As noted above, this amount is equal to demonstrated merger savings of $10,874,857 grossed up for an uncollectible factor of 1.82 percent (Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 1). Accordingly, National Grid seeks to recover $11,080,351 annually in merger-related

[244] In its initial filing, National Grid indicated that the application of the tracking mechanism demonstrates a merger savings of $13,331,198, which exceeds the annual merger-related savings allowance cap of $12,300,000 and, accordingly, proposed a merger savings allowance equal to the capped amount of $12,300,000 (Exhs. NG-MDL-1, at 98; NG-MDL-6-Colonial Gas at 1). However, National Grid discovered certain errors in its calculations during the proceeding and subsequently amended its proposed merger savings allowance to be $11,080,351 (Exh. NG-MDL-6-Colonial Gas (Rev 3) at 1).

costs as a merger savings allowance in its cost of service (Exh. NG-MDL-2-Colonial (Rev. 3) at 7, 29).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General states that for ratemaking purposes, the merger savings allowance calculation consists of three separate parts: (1) the PBR escalation of Colonial Gas' cast-off revenue requirement determined in D.T.E. 98-128; (2) the adjustment of this amount for load growth; and (3) the appropriate depiction of costs resulting from the Eastern-Colonial Gas merger (Attorney General Brief at 91). As described below, the Attorney General contends that National Grid's merger savings calculations are overstated and, therefore, National Grid seeks to recover from ratepayers too high a level of merger related costs (Attorney General Brief at 96; Attorney General Reply Brief at 28).

ii. Productivity Offset and Accumulated Inefficiencies Factor

The Attorney General contends that National Grid failed to recognize the correct productivity offset in its PBR escalation of Colonial Gas revenue requirements from 1999 through 2003 by using a 0.5 percent productivity offset, which excludes any value for an accumulated inefficiencies factor (Attorney General Brief at 91, 93). The Attorney General claims that the Department required in D.T.E. 98-128, at 65, that the productivity offset be fixed at 1.5 percent, which includes a value of 1.0 percent for the accumulated inefficiencies factor (Attorney General Brief at 92-93). The Attorney General claims that this 1.5 percent productivity offset should be applied until such time as a different percentage is found appropriate as a result of Boston Gas' appeal of the Department's Order establishing the productivity offset (Attorney General Brief at 92-93, citing D.T.E. 98-128, at 65).

The Attorney General claims that, contrary to the assertion of National Grid, in Boston Gas Company v. Dep't of Telecommunications and Energy, 436 Mass. at 238, the Supreme Judicial Court did not reject or invalidate the Department's adoption of an accumulated inefficiencies factor but instead affirmed the Department's conclusion that accumulated inefficiencies exist, finding: "the [D]epartment's conclusion that inefficiencies are embedded in the company's cast off rate as a result of [cost of service/rate of return] regulation is supported by substantial evidence" (Attorney General Brief at 93; Attorney General Reply Brief at 30). The Attorney General argues that, although the Supreme Judicial Court overturned the Department's quantification of the value of the accumulated inefficiencies factor for Boston Gas, that point is irrelevant for Colonial Gas because the decision in D.T.E. 98-128 expressly fixed the accumulated inefficiencies factor value for Colonial Gas at the one approved in D.T.E. 96-50 (Attorney General Brief at 93). Accordingly, the Attorney General claims that National Grid has offered no evidence that the accumulated inefficiencies factor should be anything other than the 1.0 percent value set by the Department in D.T.E 98-128 (Attorney General Reply Brief at 29).

The Attorney General rejects National Grid's argument that, because the Supreme Judicial Court found that the record in D.P.U. 96-50 was insufficient to determine the value of the accumulated inefficiencies factor for Boston Gas, the value should be zero for all other Massachusetts gas distribution companies (Attorney General Reply Brief at 31). The Attorney

General argues that a lack of evidence is not the same as evidence of zero value for the accumulated inefficiencies factor, adding that the productivity offset included something more than the accumulated inefficiencies factor and that those other components had sufficient evidence to withstand appeal (Attorney General Reply Brief at 31). The Attorney General claims that theSupreme Judicial Court did not set the value of accumulated inefficiencies factor for Colonial Gas to zero, nor did it do so for Boston Gas or any other utility (Attorney General Reply Brief at 33).

The Attorney General notes Colonial Gas was not the subject of the appeal, and argues that merely because a factual issue was resolved in one way for one company does not somehow determine that issue for another utility (Attorney General Reply Brief at 33, citing Attorney General v. Department of Public Utilities, 453 Mass. 191, 200 (2009)). The Attorney General asserts that Colonial Gas did not appeal the D.T.E. 98-128 Order approving its merger or seek timely reconsideration of the quantification of the 1.0 percent accumulated inefficiencies factor and, therefore, there is no lawful method to change the D.T.E. 98-128 Rate Plan requirements now (Attorney General Brief at 93; Attorney General Reply Brief at 29, citing Box Pond Association v. Energy Facilities Siting Board, 435 Mass. 408, 419 (2001)).

Finally, the Attorney General argues that it is far too late and prejudicial now, eleven years after the initial Order, and after the conclusion of the merger-related rate freeze, to change the Rate Plan (Attorney General Brief at 93-94; Attorney General Reply Brief at 29). The Attorney General asserts that Colonial Gas, having gained the full benefit of the rate freeze and keeping the savings from cost reductions related to the merger, should not be permitted now to upset the balance between customer and shareholder benefits from the merger approved under G.L. c. 164, § 96 by picking a new and lower value for the accumulated inefficiencies factor (Attorney General Reply Brief at 29).

iii. Adjustment for Firm Throughput Growth

The Attorney General notes that, in its revised filing, National Grid applied the PBR escalation on the cast-off revenue requirements over an eleven-year period from mid-year 2000 through mid-year 2011; however, it inappropriately adjusted revenues for load growth over a twelve-year period starting in mid-year 1999 (Attorney General Reply Brief at 35, citing Exh. NG-MDL-6-Colonial Gas (Rev. 1) at 1). Also, the Attorney General submits that National Grid used an adjustment for growth in firm throughput, based on the twelve-year period from 1997 to 2009 as initially filed (Attorney General Reply Brief at 35, citing Exh. NG-MDL-6-Colonial Gas (Rev. 1) at 1). The Attorney General argues that National Grid's approach of applying the firm throughput growth for a period that is different from the period for escalating the cast-off revenue requirement is incorrect (Attorney General Brief at 94, citing Exh. AG-LS (Vol. 2), at 7). The Attorney General maintains that both the PBR escalation of the cast-off revenue requirement and the adjustment for growth in firm throughput should use the same number of years over the same period (Attorney General Reply Brief at 33-34). Therefore, the Attorney General recommends applying the twelve-year PBR escalation from 1999 to 2011 and the load growth rate of 11.68 percent for the same period from 1999 to 2011 (Attorney General Reply Brief at 36).

The Attorney General disputes National Grid's claim that the Department did not adjust test year-end rate base in D.T.E. 98-128 for the cost of mains and services and similar capital investments that would have to be made to add customers over time and, therefore, that the revenue adjustment for growth should start in 1997 (Attorney General Brief at 94, citing Exh. NG-MDL-Rebuttal-1, at 11; Attorney General Reply Brief at 33). The Attorney General contends that the cast-off revenue requirement established in D.T.E. 98-128 was not based on a strict historic 1997 test year but, instead, on more of a predicted test year, reflecting the Department's modification of its ratemaking principles (Attorney General Brief at 94, citing Tr. 17, at 2423). The Attorney General argues that although that cast-off revenue requirement did not include post-1997 additions for numbers of customers, it included inflation and wage adjustments that went beyond 1999 and that are estimated by the Attorney General to be in excess of $1 million (Attorney General Brief at 94, citing Tr. 17, at 2423).

The Attorney General argues that, more important than what was or was not included in the cast-off revenue requirement, is the fact that National Grid agreed to the Department's approved cast-off revenue requirement in D.T.E. 98-128 by failing to appeal that Order (Attorney General Brief at 95; Attorney General Reply Brief at 34). Accordingly, the Attorney General contends that that there is no reason to modify the starting point for the merger savings allowance calculation in this case (Attorney General Brief at 95, citing Tr. 17, at 2422; Attorney General Reply Brief at 34).

iv. Savings from Unrelated Mergers

The Attorney General claims that National Grid's calculation of the merger savings allowance incorrectly fails to incorporate reductions in its current revenue requirements that resulted from the 2000 KeySpan acquisition of Eastern and the 2007 merger of National Grid and KeySpan (Attorney General Brief at 95). The Attorney General asserts that the scope of the Department's Order in D.T.E. 98-128 and common sense support the conclusion that Colonial Gas' merger savings should be considered to determine what additional Colonial Gas acquisition premiums are to be recovered from Colonial Gas' customers (Attorney General Brief at 95-96, citing Exh. NG-MDL-Rebuttal-1, at 11).[245]

The Attorney General claims that the combined merger savings from the 2000 KeySpan acquisition of Eastern and the 2007 merger of National Grid and KeySpan are approximately $3.0 million (Attorney General Reply Brief at 36-37, citing Exh. AG-LS-2, at 2). Accordingly, the Attorney General proposes that this amount be removed from National Grid's merger savings allowance calculations (Attorney General Reply Brief at 36-37, citing Exh. AG-LS-2, at 2).

The Attorney General states that she has provided an adequate factual basis for accounting for the savings due to these two mergers (Attorney General Reply Brief at 38,

245 By not including the savings generated from other mergers, the resulting cost of service of Colonial Gas in the instant case would correspondingly increase by that same amount of savings. In turn, the merger savings allowance would decrease by the same amount because the tracking mechanism approved in D.T.E. 98-128 calculates the merger savings allowance as the difference between the net inflation-adjusted Colonial Gas revenue requirement and Colonial Gas' cost of service.

citing Exhs. AG-1-28, Att. (I)(2) at 3; AG-22-2; AG-25-6). The Attorney General states that the information she used to perform her calculations relates to the merger savings allocation and allocators used by the National Grid service companies and was uncontested during the proceeding (Attorney General Reply Brief at 38, citing Exhs. AG-1-28, Att. (I)(2) at 3; AG-22-2; AG-25-6).[246]

v. Ratemaking Treatment of Goodwill

The Attorney General argues that National Grid inappropriately seeks to recover the amortization of the Colonial Gas acquisition premium as an expense in National Grid's revenue requirement (Attorney General Reply Brief at 41). The Attorney General claims that the amortization of the acquisition premium existed as a merger-related expense only because the then applicable accounting standards required such treatment at the time the D.T.E. 98-128 Order was issued (Attorney General Reply Brief at 40). Accordingly, the $12.3 million merger savings allowance established in D.T.E. 98-128 included $8.2 million for the revenue requirement associated with the amortization of the acquisition premium (Attorney General Reply Brief at 40, citing D.T.E. 98-128, at 92).

However, the Attorney General argues that due to a change in accounting requirements, National Grid is no longer amortizing the Colonial Gas acquisition premium and cannot do so under the current applicable accounting standards (Attorney General Reply Brief at 39). Specifically, the Attorney General states that the presently applicable accounting standards

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[246] The Attorney General argues that the approximately $1 million reduction in the Colonial Gas rate year cost of service that was identified in Exhibit NG-MDL-6-Colonial (Rev. 1) should be reflected in the merger savings calculation even if the original escalation period is used (Attorney General Reply Brief at 38-39).

provide for no amortization of the acquisition premium and that the acquisition premium remains on the books, subject to evaluation for impairment (Attorney General Reply Brief at 40, citing Exh. AG-DJE, at 10). The Attorney General asserts that, absent any adjustment to the acquisition premium for impairment, there is no amortization or expense to recognize diminution in the book value of the premium over time (Attorney General Reply Brief at 40, citing Exh. AG-DJE, at 10).

The Attorney General asserts that recovery of this "non-existent" amortization would force customers to pay for something that does not exist (Attorney General Reply Brief at 40). The Attorney General argues that National Grid cannot logically argue that the recovery of the amortization of the acquisition premium was appropriate at the time of D.T.E. 98-128, because the accounting rules at that time required it, but that the present accounting rules, which prohibit such amortization, are irrelevant (Attorney General Reply Brief at 40-41). Because National Grid is seeking to recover an amortization expense that does not exist, the Attorney General argues that the Department should not allow the inclusion of such "phantom" expenses in National Grid's revenue requirement, notwithstanding that the acquisition premium has not been written off but remains on the books (Attorney General Reply Brief at 41).

b. National Grid

i. Productivity Offset and Accumulated Inefficiencies Factor

National Grid explains that in calculating the merger savings, it started with the approved cast-off revenue requirement for Colonial Gas and adjusted this amount for inflation less productivity offset (National Grid Brief at VII.5-6). National Grid states that it (1) used the productivity offset of 0.5 percent that was in place for Boston Gas for each year from 1999 through 2003, and (2) used the productivity offset of 0.41 percent for each year from 2004 through 2010 (National Grid Brief at VII.5-6).

Contrary to the position of the Attorney General, National Grid asserts that, in calculating the merger savings, it used the correct productivity offset of 0.5 percent from 1999 to 2003 (National Grid Brief at VII.6). National Grid claims that, in D.T.E. 98-128, at 63, the Department stated that it was adopting the Boston Gas productivity offset in the tracking mechanism for Colonial Gas (National Grid Reply Brief at 64-65). Specifically, the Department's Order provided: "Petitioners shall employ the 1.5 percent productivity offset until such time as a different percentage is found appropriate as a result of (1) Boston Gas' appeal to the [Supreme Judicial Court] regarding the productivity offset for the first term of Boston Gas' PBR plan, and (2) a new productivity offset is devised for Boston Gas subsequent to the first term of its PBR plan" (National Reply Brief at 62, citing D.T.E. 98-128, at 63). National Grid claims that when the Department issued D.T.E. 98-128, it acknowledged that the Supreme Judicial Court's decision was pending and that the outcome of the Boston Gas appeal had relevance to the Colonial Gas productivity offset (National Reply Brief at 65-66). National Grid claims that because the appeal was pending, the Department resolved the issues in D.T.E. 98-128 by using the 1.5 percent productivity offset established in D.P.U. 96-50 and D.P.U. 96-50-C as a placeholder for the Colonial Gas merger savings tracking mechanism until such time as a new offset was established for Boston Gas (National Grid Reply Brief at 66, citing D.T.E. 98-128, at 63).

National Grid disputes the Attorney General's claim that the above-referenced language from the Order in D.T.E. 98-128 expressly fixed the accumulated inefficiencies factor value for Colonial Gas at 1.0 percent, which results in a productivity offset of 1.5 percent, until a new productivity offset is determined for Boston Gas (National Grid Brief at VII.8; National Reply Brief at 62). National Grid contends that the Attorney General's interpretation of the Department's Order would mean that the Department intended to establish a value for an accumulated inefficiencies factor for Colonial Gas that would operate independent of the Boston Gas accumulated inefficiencies factor and only until the next Boston Gas proceeding in which a new accumulated inefficiencies factor was set (National Grid Reply Brief at 62). National Grid asserts that this interpretation would render clause (1) of that Order irrelevant and would attach no import to the outcome of the Supreme Judicial Court proceeding (National Reply Brief at 63).

National Grid claims that there is no basis in the Department's Order in D.T.E. 98-128 for the claim that the value of the Boston Gas accumulated inefficiencies factor is inapplicable to Colonial Gas for purposes of the merger savings tracking mechanism (National Grid Brief at VII.8-9). National Grid argues that although the Supreme Judicial Court may have affirmed the Department's discretion to set an accumulated inefficiencies factor, the quantification of the value of that factor is zero from a legal perspective, until such time that the Department conducts a proceeding to quantify the factor based on substantial evidence in the record of an adjudicatory proceeding (National Grid Brief at VII.9). National Grid adds that the Department did not conduct such a proceeding and therefore, the productivity offset that applies to the Colonial Gas tracking mechanism is the same as that applying to Boston Gas in the years 1999 through 2003, i.e., 0.50 percent (National Grid Brief at VII.9, citing Exh. NG-MDL-6-Colonial Gas (Rev.1)).

National Grid asserts that any evidence substantiating the 1.0 percent accumulated inefficiencies factor for Colonial Gas would have had to be presented in D.T.E. 98-128 and referenced by the Department in its Order (National Grid Brief at VII.10). Instead, National Grid claims that the Department did not cite to evidence for Colonial Gas but, rather, applied the Boston Gas factor to Colonial Gas based on evidence regarding industry productivity presented in D.P.U. 96-50 and D.P.U. 96-50-C that was later invalidated by the Supreme Judicial Court (National Grid Brief at VII.10). Accordingly, National Grid concludes that as of the date of the Supreme Judicial Court's issuance of its order vacating the Department's decision in D.T.E. 96-50-D, no accumulated inefficiencies factor existed and none applied either to Boston Gas or to the Colonial Gas tracking mechanism (National Reply Brief at 68).

ii. Adjustment for Firm Throughput Growth

Contrary to the position of the Attorney General, National Grid argues that it is not appropriate to apply the increase in firm throughput growth for the eleven-year period from 1999 through 2011. Instead, National Grid argues that it correctly applied the increase in firm throughput growth for the twelve-year period following the 1997 test year in D.T.E. 98-128 through 2009, the test year in the instant case (National Grid Brief at VII.10; National Grid Reply Brief at 69). National Grid contends that the Attorney General's argument, which requires that the years used to calculate sales growth should match the years used to calculate the PBR inflation factor, is not supported by D.T.E. 98-128 or Department ratemaking precedent (National Grid Brief at VII.10; National Grid Reply Brief at 69).

More specifically, National Grid claims that in D.T.E. 98-128, the Department found it unreasonable to adjust revenues to account for system growth without a corresponding adjustment in base rates (National Grid Brief at VII.11, citing D.T.E. 98-128, at 19; National Grid Reply Brief at 72).[247] National Grid claims that the purpose of the merger savings tracking mechanism established in D.T.E. 98-128 is to calculate the revenue requirement that would have existed had Colonial Gas not merged with Eastern Enterprises in 1999 and had operated on a stand-alone basis through the next rate case following the expiration of the ten-year rate freeze (National Grid Brief at VII.11, citing D.T.E. 98-128, at 64).

National Grid explains that Department ratemaking precedent creates a gap between the period of sales growth, included in the cast-off revenue requirement, and the application of the PBR inflation factor (National Grid Reply Brief at 71, citing Bay State Gas Company, D.T.E. 05-27, at 408).[248] National Grid states that the reason for this gap is that the PBR inflation

[247] National Grid claims that, in D.T.E. 98-128 only sales growth occurring prior to the year ending December 31, 1997 was included in the cast-off revenue requirement while the PBR inflation factor was set to apply after the midpoint of the rate year (National Reply Brief at 72).

[248] For example, National Grid notes that in D.T.E. 05-27, the Department established that the first rate adjustment under its PBR plan applying the PBR inflation factor was to take place on November 1, 2006, one year after the date of the Department's Order setting the cast-off rates with a 2004 test year, which created a gap between the period of sales growth included in the cast-off revenue requirement and the application of the PBR inflation factor (National Grid Reply Brief at 71, citing D.T.E. 05-27, at 408). National Grid explains that by the time new base rates were reset in the company's next rate case, D.P.U. 09-30, those base rates were set to capture five years of sales growth,

factor adjustments do not begin until some period of delay after the rate year, while where sales growth is captured in the next rate case as of the end of the test year for the prior case (National Grid Reply Brief at 71). National Grid asserts that the same method applies in calculating the stand-alone revenue requirement for Colonial Gas, under the merger savings tracking mechanism that accounts for twelve years of sales growth and eleven years of PBR-type adjustments (National Grid Reply Brief at 71).

iii. Savings from Unrelated Mergers

National Grid disputes the Attorney General's claim that its calculations inappropriately failed to account for merger savings resulting from the acquisition of Eastern Enterprises in 2000 by KeySpan and the 2007 merger of National Grid and KeySpan (National Grid Brief at VII.12). National Grid asserts that there is no basis for reducing the calculation by the savings that may have occurred in those subsequent mergers (National Grid Reply Brief at 72-73).

National Grid argues that the Attorney General has failed to cite to any language in the Department's Order in D.T.E. 98-128 to support her suggested $3.0 million deduction related to other mergers (National Grid Reply Brief at 73). National Grid adds that there is no evidence in the record that any of the KeySpan-Eastern Enterprises merger savings estimated at a total of $40 million have any relation to Colonial Gas, nor does the record confirm that those savings were achieved (National Grid Reply Brief at 73, citing Exh. AG-22-2). National Grid

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or sales growth occurring after the end of the test year, December 31, 2004 (i.e., 2005, 2006, 2007, 2008 and 2009), while Boston Gas had received only three annual PBR adjustments (2006, 2007, 2008), or four, if the base-rate increase effective November 1, 2009 is counted (National Grid Reply Brief at 71).

concludes that the calculation of the $3.0 million adjustment is without record evidence (National Grid Reply Brief at 73).

National Grid claims that the productivity offset applied to a cast-off revenue requirement of approximately $90.8 million would require the Company to generate approximately $450,000 per year in annual O&M savings, over and above the consolidation savings from the Eastern-Colonial Gas merger, with the annual amounts increasing as the revenue requirement increases over time (National Grid Reply Brief at 73, citing Exh. NG-MDL-6-Colonial Gas (Rev. 1) at 1). National Grid adds that over a ten-year period, this would require Colonial Gas to generate approximately $4.5 million in operating savings, which exceeds the $3.0 million in merger related savings claimed by the Attorney General (National Grid Reply Brief at 73-74).

National Grid argues that there is nothing about the productivity adjustment that is designed to exclude the effect of mergers, claiming that the effect of mergers has been one of the most significant drivers of industry productivity (National Reply Brief at 74, citing Exh. DPU-1-2; D.P.U. 09-30, at 24). National Grid claims that the operation of the tracking mechanism, which is designed to calculate the stand-alone cost of service at the end of the ten-year rate freeze, and the fact that Colonial Gas is eligible to recover merger-related costs only if merger savings are demonstrated over and above the productivity gains, means that the productivity offset works to reduce the stand-alone cost of service each year as the PBR progresses (National Grid Reply Brief at 74-75). National Grid contends that, given that merger-related savings and the productivity offset are linked, reducing the stand-alone cost of service again to account for $3.0 million in alleged savings attributable to Colonial Gas' operations as a result of the KeySpan and National Grid mergers has the potential to double count efficiencies mandated by the productivity offset (National Grid Reply Brief at 75). National Grid asserts that such an adjustment would be inappropriate especially where there is no provision in the D.T.E. 98-128 Order to allow for such a reduction, and there is no case law, Department precedent, or even a technical basis for such a deduction (National Grid Reply Brief at 75).

National Grid adds that the Department has recognized that mergers and acquisitions are tools that may be used to reduce operating costs and therefore, are and appropriate approach to achieving productivity gains anticipated in the merger tracking mechanism (National Grid Brief at VII.13).[249] National Grid asserts that the Attorney General has provided no factual or legal basis for the deduction of merger synergies associated with the KeySpan and National Grid mergers from the calculation of savings under the D.T.E. 98-128 tracking mechanism (National Grid Brief at VII.13).

iv. Ratemaking Treatment of Goodwill

National Grid disputes the Attorney General's claims that, because Colonial Gas is no longer recording the amortization of the acquisition premium paid to complete the

[249] National Grid states that the Department has acknowledged that mergers and acquisitions are desirable generally, because of savings from economies of scope and scale, such that completing the subsequent mergers was a legitimate strategy to reduce operating costs and gain efficiencies and that customers have already received the benefits of these mergers, including gas-cost savings and a ten-year rate freeze (National Grid Reply Brief at 74, citing D.T.E. 98-128, at 36-37 n.30; D.T.E. 98-27, at 6 n.8, 66).

Eastern-Colonial Gas merger due to a change in accounting treatment, the revenue requirement of that amortization should be excluded from the determination of Colonial Gas' cost of service (National Grid Brief at VII.14). Instead, National Grid argues that the change in accounting treatment does not change the cost recovery associated with the payment paid to purchase the goodwill asset (National Grid Reply Brief at 77, citing Exh. DPU-AG-2-5, at 6).

National Grid asserts that Eastern Enterprises actually incurred the cost of the acquisition premium in completing the merger with Colonial Gas and that the acquisition premium remains on Colonial Gas' books (National Grid Brief at VII.14, citing D.T.E. 98-128, at 91-96; Tr. 19, at 2776-2777; National Grid Reply Brief at 75-76). However, National Grid asserts that, due to a change in generally accepted accounting principles, Colonial Gas is now precluded from amortizing goodwill on its books. Rather, it must account for goodwill through an "impairment test," which requires a write-down of the goodwill asset when the amount of goodwill exceeds an asset's implied fair value and, therefore, goodwill is no longer eligible to be amortized (National Grid Brief at VII.14, citing Tr. 19, at 2782; Exh. DPU-AG-2-5, at 12).

National Grid argues that the Department allowed the recovery of merger-related costs by conditioning the recovery of those costs on the demonstration of merger-related savings and not any requirement regarding the accounting treatment afforded to the resulting asset recorded on Colonial Gas' books at any particular time following the acquisition (National Grid Reply Brief at 75, citing D.T.E. 98-128, at 95-96). National Grid contends that the accounting treatment on which the Attorney General has relied to support her argument pertains to the valuation of an asset and not to the accounting treatment of payment of funds used to acquire the operations of Colonial Gas (National Grid Reply Brief at 76). National Grid claims that the annual amortization of the goodwill asset simply represents a mechanism for valuing the goodwill asset over time, not a mechanism for determining the cost incurred by Colonial Gas to consummate the transaction (National Grid Reply Brief at 76, citing Exh. DPU-AG-2-5, Att. at 6). National Grid argues that, although the inherent value of the organization was augmented by the merger, giving rise to the goodwill asset, the Attorney General inappropriately suggests that the Department strip Colonial Gas of the recovery of the costs that were incurred to create that value (National Grid Reply Brief at 77).

National Grid adds that it is not seeking recovery of "non-existent" amortizations as the Attorney General claims (National Grid Reply Brief at 77, citing Attorney General Reply Brief at 40). Instead, the Companies maintain that Colonial Gas was only allowed to retain operating savings generated by the merger in order to offset the costs to complete that merger (National Grid Reply Brief at 77). National Grid adds that the amortization recorded each year on Colonial Gas' books reduces the value of the asset purchased by Colonial Gas, but has no effect on the cost incurred to purchase that asset (National Grid Reply Brief at 77).

3. Analysis and Findings

a. Introduction

The Department must determine whether National Grid's proposal to recover Colonial Gas' merger-related costs through base distribution rates set in this proceeding is consistent with and complies with the Department's directives in D.T.E. 98-128, and results in just and reasonable rates. As described in further detail above, to determine the savings associated with the Eastern-Colonial Gas merger, Colonial Gas' revenue requirement, assuming it had remained a stand-alone company, is compared to Colonial Gas' revenue requirement as a merged company at the end of year ten of the rate freeze period. D.T.E. 98-128, at 9. Any savings associated with the Eastern-Colonial Gas merger are used to determine the (1) amount of any recoverable acquisition premium[250] and (2) return on the cash advance[251] in years eleven through 40. D.T.E. 98-128, at 9-10. The Department's Order in D.T.E. 98-128 allows the recovery through distribution rates of up to $12.3 million per year after the expiration of the rate freeze, over a 30-year period so long as savings related to the Eastern-Colonial Gas merger are demonstrated to have been obtained during the ten-year rate freeze to offset the

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250 In D.T.E. 98-128, Eastern and Colonial Gas proposed to recover over a period of 40 years the acquisition premium of $199.2 million, or equivalent to $8.2 million per year on a pre-tax basis. D.T.E. 98-128, at 91-92 & n.70. The Department noted that "Eastern shareholders, not Colonial Gas ratepayers, would bear any risk that operational savings and synergies arising from the merger would be insufficient to cover the annual amortization of the acquisition premium . . . ." D.T.E. 98-128, at 96. The Department added that after the ten-year rate freeze and "during the next 30 years, recovery of the acquisition premium must be supported by demonstrated savings" D.T.E. 98-128, at 96.

251 In D.T.E. 98-128, Eastern and Colonial Gas proposed to recover over a period of 40 years the interest expense associated with a $144.0 million cash investment used to pay for the acquisition of Colonial by Eastern, or equivalent to $4.1 million in annual interest expense. D.T.E. 98-128, at 96-97. The Department stated that Colonial Gas' ratepayers would pay only the interest on the $144.0 million cash investment and not a regulated return. D.T.E. 98-128, at 99-100. The Department also noted that if the merger related synergies were insufficient to cover the $4.1 million annual interest expense associated with the $144.0 million cash investment, Eastern's shareholders would be at risk for the shortfall. D.T.E. 98-128, at 96.

amount sought for recovery through rates (Exh. NG-MDL-1, at 94, citing D.T.E. 98-128, at 8-12, 16 n.19, 17-20, 62-64).

The Attorney General raised a number of issues relating to the appropriateness of National Grid's calculations of the merger savings allowance based on and applying the tracking mechanism established in D.T.E. 98-128. These issues include: (1) the productivity offset, which centers on the appropriate value of the accumulated inefficiencies component of that offset; (2) the adjustment for growth in firm throughput on the PBR-adjusted cast-off revenue requirement; (3) the ratemaking treatment of the merger savings arising from mergers unrelated to the Eastern-Colonial Gas merger; and (4) the ratemaking treatment of goodwill. We address these issues below.

b. Productivity Offset and Accumulated Inefficiencies Factor

The issue relating to the correct and appropriate level of productivity offset to be applied in the annual PBR escalation of Colonial Gas' cast-off revenue requirements centers on the appropriate value of the accumulated inefficiencies factor, which is a component of the productivity offset to be used from the start of the ten-year rate freeze until November 2003 when a new productivity offset was established. In D.T.E. 98-128, at 63, the Department found that because productivity offsets are not company-specific, it was appropriate to use a productivity offset developed for another local gas distribution company for the purpose of that case, and accordingly found that it is reasonable to use the same productivity offset implemented for Boston Gas in the tracking mechanism for Colonial Gas. The Department stated that "for the purpose of determining what Colonial Gas' revenue requirement would be at the end of year ten of the rate freeze had Colonial Gas operated on a stand-alone basis, [National Grid] shall employ the 1.5 percent productivity offset until such time as a different percentage is found appropriate as a result of (1) Boston Gas' appeal to the [Supreme Judicial Court] regarding the productivity offset for the first term of Boston Gas' PBR plan, and (2) a new productivity offset is devised for Boston Gas subsequent to the first term of its PBR plan." D.T.E. 98-128, at 64.[252]

No party objected to the application of the productivity offset of 0.41 percent determined in D.T.E. 03-40 after the expiration of the first term of Boston Gas' PBR plan. Thus, the issue rests on the application of clause (1) of the above-quoted two-part clause of the Department's Order in D.T.E. 98-128.

National Grid maintains that the correct productivity offset should be 0.5 percent, which means that the accumulated inefficiencies factor is equal to zero, because the Supreme Judicial Court vacated the Department's Orders establishing the latter factor (National Grid Reply Brief at 67-68). National Grid also contends that, in D.T.E. 96-50-D, following remand of its previous Orders in D.P.U. 96-50 (Phase I) and D.P.U. 96-50-C (Phase I), the Department directed that the effective date of the application of this reduced accumulated inefficiencies factor and the corresponding productivity offset is retroactively effective as of November 1, 1999 (National Grid Reply Brief at 67, citing D.T.E. 96-50-D at 11). Below, we

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[252] The first term of Boston Gas' PBR plan was from December 1, 1996, through November 30, 2001. D.T.E. 98-128, at 64 n.45, citing D.P.U. 96-50 (Phase I) at 260). This first term was intended to continue beyond 2001 unless (1) the Department, Boston Gas, or other parties sought modifications to the plan, and (2) the Department determined that modifications are necessary. D.P.U. 96-50 (Phase I) at 260.

review the various Department Orders and the outcome of Boston Gas' appeals to the Supreme Judicial Court as a basis for determining the appropriate value of the accumulated inefficiencies factor and the corresponding productivity offset applicable to Colonial Gas.

In D.P.U. 96-50 (Phase I), the Department approved a 2.0 percent productivity offset for Boston Gas. D.P.U. 96-50 (Phase I) at 283, n. 130.[253] In Boston Gas Company, D.P.U. 96-50-C (Phase I) (1997), the Department granted the company's motion for reconsideration and reduced the consumer dividend factor from 1.0 percent to 0.5 percent but denied the company's motion for reconsideration relating to the accumulated inefficiencies factor keeping the value of that factor at the initially approved level of 1.0 percent. D.P.U. 96-50-C (Phase I) at 58-59.[254]

In Boston Gas Company, D.P.U. 96-50-D (Phase I), following remand[255] by the Supreme Judicial Court of the Department's Orders in D.P.U. 96-50 (Phase I) and D.P.U. 96-50-C (Phase I), the Department retained the accumulated inefficiencies factor but reduced it

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253 This 2.0 percent productivity offset is equal to a total productivity factor differential of 0.1 percent (0.1 = 0.4 – 0.3 percent), plus an input price differential of - 0.1 percent (-0.1 = 3.7 – 3.6), plus a consumer dividend of 1.0 percent, plus an accumulated inefficiencies factor of 1.0 percent (2.0 = 0.1 – 0.1 + 1.0 + 1.0).

254 The resulting productivity offset as a result of the Department's Order in D.P.U. 96-50-C (Phase I) was 1.5 percent.

255 The Department's Orders in D.P.U. 96-50 (Phase I) and D.P.U. 96-50-C (Phase I) relating to the use of a 1.0 percent accumulated inefficiencies factor were remanded to the Department on August 16, 1999 (Exhs. NG-MDL-1, at 97; DPU-8-5, Atts. DPU-8-5(A); DPU-8-5(B); see also Boston Gas Company v. Department of Telecommunication and Energy, 436 Mass. at 236).

from 1.0 percent to 0.5 percent.[256] D.P.U. 96-50-D (Phase I) at 6; Boston Gas Company vs. Department of Telecommunications and Energy, 436 Mass. at 236.[257]

The Supreme Judicial Court subsequently vacated those portions of D.T.E. 96-50-D that imposed an accumulated inefficiencies factor of 0.5 percent based on a finding that the quantification of the factor was not supported by substantial evidence. Boston Gas Company vs. Department of Telecommunications and Energy, 436 Mass. at 242-243.[258] Although the Supreme Judicial Court upheld the Department's decision to impose an accumulated inefficiencies factor as based on careful consideration supported by substantial evidence, the Court also ruled that there was no substantial evidence to support a specific value for this factor.[259] The Supreme Judicial Court's ruling only vacated the accumulated inefficiencies

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[256] Concluding that the level of accumulated inefficiencies in the gas distribution industry should be set equal to the consumer dividend, the Department found that the appropriate value for Boston Gas' accumulated inefficiencies factor was 0.5 percent D.T.E. 96-50-D (Phase I) (2001) at 6-7.

[257] Although National Grid indicated that the basis for its proposed 0.5 percent productivity offset, applied from January 2000 through October 2003, is the Department's Order in Boston Gas Company, D.T.E. 96-50-D (Phase I) (2001) that reduced the initially-determined accumulated inefficiency factor from 1.0 percent to 0.5 percent, the resulting productivity offset as a result that Order was 1.0 percent, not 0.5 percent (Exh. DPU-8-5, Att. C at 5). Nevertheless, National Grid filed schedules using a productivity offset of 0.5 percent (see, e.g., Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 3).

[258] The resulting productivity offset as a result of the vacation of the Department's Order in D.P.U. 96-50-D (Phase I) is 0.5 percent, which National Grid used in its filed schedules (see, e.g., Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 3).

[259] The Supreme Judicial Court stated that "if the underlying rationale of adopting PBR is that it drives a company to greater efficiency, the [D]epartment can conclude, as a matter of common sense, that the company has built up inefficiencies under [cost of

factor component of that productivity offset. Therefore, the other components of Boston Gas' productivity offset, including the productivity factor differential of 0.1 percent, the input price differential of - 0.1 percent, and the consumer dividend of 0.5 percent, remained valid and effective until replaced by another productivity offset in a subsequent proceeding, D.P.U. 03-40.

The Attorney General argues that although the Supreme Judicial Court overturned the Department's quantification of the value of the accumulated inefficiencies factor for Boston Gas, its decision does not apply to Colonial Gas because the Department's Order in D.T.E. 98-128 expressly fixed the accumulated inefficiencies factor value for Colonial Gas at the value approved in D.T.E. 96-50 and Colonial Gas did not appeal the Department's Order in D.T.E. 98-128 (i.e., 1.0 percent) (Attorney General Brief at 93; Attorney General Reply Brief at 29).

The Attorney General correctly notes that Colonial Gas did not appeal the Department's Order in D.T.E. 98-128. Therefore, had the Department adopted a fixed accumulated inefficiencies factor for Colonial Gas in D.T.E. 98-128, National Grid would have no basis to change it based on the Supreme Judicial Court's orders related to another company. However, the Department did not adopt a fixed accumulated inefficiencies factor for Colonial Gas. Rather, the factor was expressly conditioned on the outcome of "Boston Gas' appeal to the

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service/rate of return regulation], and that the consumer should share in the gains as these inefficiencies are discovered and eliminated." Boston Gas Company vs. Department of Telecommunications and Energy, 436 Mass. at 238-239. The Supreme Judicial Court added that "the Department's inference is based on a theory adopted after careful consideration . . . [t]hus, we hold that the imposition of the accumulated inefficiencies factor was within the [D]epartment's discretion and is supported by substantial evidence" Boston Gas Company vs. Department of Telecommunications and Energy, 436 Mass. at 239.

[Supreme Judicial Court] regarding the productivity offset for the first term of Boston Gas' PBR plan." D.T.E. 98-128, at 64. As noted above, the productivity offset for the first term of Boston Gas' PBR plan as a result of the outcome of the appeal was 0.5 percent. Accordingly, the Department finds that the appropriate level of productivity offset to be applied in the tracking mechanism for calculating the merger savings of Colonial Gas from January 2000 through October 2003 is 0.5 percent, which includes a value of zero percent for the accumulated inefficiencies factor.

c. Adjustment for Firm Throughput Growth

The following factors are used to escalate Colonial Gas' cast-off revenue requirement: (1) the actual GDP-PI experienced each year during the ten-year rate freeze, and (2) the productivity offset used in the Boston Gas PBR in each of those years adjusted for firm throughput. D.T.E. 98-128, at 11-12; see also, Exh. DPU-1, at 27-28; Tr. 3, at 265-267. National Grid used the actual GDP-PI indices in determining the annual inflation rates (Exhs. NG-MDL-6-Colonial Gas (Rev. 3) at 1, 3-4; DPU-8-1, Att. at 1-2). In addition, as found above, National Grid applied the correct productivity offset of 0.5 percent from 1999 to 2003 in determining the net inflation adjustment for the purpose of the PBR escalation of Colonial Gas' cast-off revenue requirement.

In D.T.E. 98-128, at 34-35, the Department specified that the cast-off revenue requirements should include wage increases effective January 1, 1998 and January 1, 1999. For the year 2000, the Department specified that the calculation of the cast-off revenue requirement should include wage increases only for the period from January 1, 2000 to June 30, 2000. D.T.E. 98-128, at 34-35.

In its revised filing dated July 7, 2010, as well as its updated filing on September 24, 2010, National Grid changed the PBR escalation of the cast-off revenue requirement by applying the net inflation adjustment starting on July 1, 2000, instead of starting on August 1, 1999 as originally proposed (Exhs. NG-MDL-Rebuttal-1, at 13; NG-MDL-6-Colonial Gas (Rev. 1); NG-MDL-6-Colonial Gas (Rev. 3) at 1)).[260] We find that National Grid's revised calculations of the PBR escalation of Colonial Gas' cast-off revenue requirements beginning on July 1, 2000, is consistent with the Department's Order in D.T.E. 98-128.

The Attorney General objects to National Grid's use of a 12.7 percent load growth adjustment of Colonial Gas' stand-alone revenue requirement because this growth rate is based on the twelve-year period between 1997 to 2009, while the revised PBR escalation of Colonial Gas' cast-off revenue requirement covers the eleven-year period beginning July 1, 2000 through the mid-point of 2011, the rate year in this case (Attorney General Reply Brief

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[260] The resulting stand-alone total revenue requirement for Colonial Gas as of the mid-point of 2011 is $109,979,289, compared to the initially-filed total revenue requirement of $111,338,721 escalated from August 1, 1999 (Exhs. NG-MDL-1, at 96; NG-MDL-6-Colonial Gas at 1; NG-MDL-6-Colonial Gas (Rev 1) at 1; NG-MDL-6-Colonial Gas (Rev. 3) at 1). The corresponding stand-alone total revenue requirement adjusted for load growth as of the mid-point of 2011 is $123,948,607 compared to the initially-filed total revenue requirement adjusted for load growth of $125,480,712 (Exhs. NG-MDL-6-Colonial Gas at 1; NG-MDL-6-Colonial Gas (Rev. 1) at 1; NG-MDL-6-Colonial Gas (Rev. 3) at 1).

at 35).[261] The Attorney General recommends the use of the twelve-year PBR escalation of Colonial Gas' stand-alone revenue requirement from 1999 to 2011 and a lower load growth rate of 11.68 percent based on this same period, thereby reducing Colonial Gas' stand-alone revenue requirement by $1.1 million (Attorney General Reply Brief at 36).

As noted above, the Department's Order in D.T.E. 98-128, at 34-35 specified that, in calculating Colonial Gas' cast-off-revenue requirement, the wage increases for the period from January 1, 1998 to June 30, 2000 should be included. Accordingly, we find that National Grid's revised PBR escalation of Colonial Gas' cast-off revenue requirement covering the eleven-year period beginning July 1, 2000 through the mid-point of 2011, is consistent with the Department's Order in D.T.E. 98-128.

Regarding the appropriate period to use to adjust Colonial Gas' stand-alone revenue requirement for growth in firm throughput, the Department's ratemaking standard relies on historical test year data, adjusted only for known and measurable changes.[262] See Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); Chatham Water Company, D.P.U. 19992, at 2 (1980); Boston Gas Company, D.P.U. 18264, at 2-4 (1975); New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975). The Attorney General disputes National Grid's claim

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[261] The eleven year period is equal to the ten full years from 2001 to 2010 plus half years for 2000 and 2011 (Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 1).

[262] These changes include the effect of weather on test year billing determinants. See, e.g., D.P.U. 08-35, at 50-53; D.T.E. 05-27, at 51-54; D.T.E. 03-40, at 22-23; Boston Gas Company, D.P.U. 88-67 (Phase I) at 72-75 (1989); The Berkshire Gas Company, D.P.U. 1490, at 24 (1983).

that the revenue adjustment for growth should start in 1997 (Attorney General Brief at 94, citing Exh. NG-MDL-Rebuttal-1, at 11; Attorney General Reply Brief at 33). She argues that although that cast-off revenue requirement did not include post-1997 additions for number of customers, it included significant inflation and wage adjustments that went beyond 1999 (Attorney General Brief at 94, citing Tr. 17, at 2423).

The cast-off revenue requirement approved in D.T.E. 98-128 was based on a 1997 test year. Accordingly, National Grid provided the normalized firm throughput for the 1997 test year (Exhs. NG-MDL-6-Colonial Gas (Rev. 3); NG-MDL-7-Colonial Gas; DPU-8-2; DPU-1, at 27). The test year for this case is 2009. Thus, using the firm throughputs for 1999 and 2011 as the period to adjust Colonial Gas' stand-alone revenue requirement instead of the firm throughputs for 1997 (the test year in D.P.U. 98-128) and 2009 (the test year here), is inconsistent with the above-noted Department precedent.

Although D.T.E. 98-128 was not a rate case where base rates were established, the purpose of the tracking mechanism established in that proceeding was to determine the reasonableness of Colonial Gas' costs, absent the merger. Therefore, the Department allowed the inclusion of cost increases through June 30, 2000, for purposes of setting the cast-off revenue requirement. D.T.E. 98-128, at 34. However, the Department did not make any changes to test year billing units nor did it make any determination that allowing such post-test year cost adjustments would necessitate adjustments in the 1997 billing units.

Regarding the Attorney General's recommendation to use the 2011 firm throughput as the end point for determining the percentage increase for the adjustment in firm throughput, her proposed 2011 billing units are based on forecasted information (Exh. AG-11-13, Atts. (c), (d)). Although the Department allows post-test year PBR revenue adjustments for inflation net of productivity offset, no adjustments are made to the test year billing units for those changes that may occur during the rate year.[263] See e.g., Boston Gas Company, D.P.U. 09-86, Letter Order (2009); Bay State Gas Company, D.P.U. 07-74, Letter Order (2007).[264] Accordingly, we find that it is not appropriate to use the twelve-year period from 1999 through 2011 as the basis for determining the growth rate on firm throughput to be applied on Colonial Gas' stand-alone revenue requirement. Instead, we accept National Grid's proposal to use the 12.7 percent growth rate, representing the growth in normalized firm throughput from 1997 through 2009.

d. Savings from Unrelated Mergers

As described above, for 30 years following the expiration of the rate freeze, Colonial Gas is allowed recovery of up to $12.3 million annually of merger-related costs through distribution rates as a merger savings allowance, so long as it can demonstrate merger-related

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[263] If post-test year changes were correspondingly made in the billing determinants, such an approach would be tantamount to using a forecasted test period, which the Department has repeatedly rejected. See D.P.U. 07-50-A at 52, citing Eastern Edison Company, D.P.U. 1580, at 19 (1984); Boston Gas Company, D.P.U. 18264, at 2 (1975); New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975).

[264] For example, in D.P.U. 09-86, at 3, the Department approved the company's sixth PBR compliance filing which included, among other factors, the use of 2008 weather normalized billing determinants applied to 2009 rate year revenues reflecting adjustments for inflation net of productivity offset (October 26, 2009, Filing Letter at 2, Att. 2, at 1, 5). Similarly, in D.P.U. 07-74, at 4, the Department approved the company's second PBR compliance filing which included, among other things, the use of 2006 billing weather normalized determinants applied on 2007 rate year revenues reflecting adjustments for inflation net of productivity offset (September 14, 2007, Filing Letter, §§ 2-6).

savings realized during the ten-year rate freeze to offset the amount sought for recovery through rates. In order to calculate merger-related savings, the Rate Plan approved in D.T.E. 98-128 established a tracking mechanism designed to determine: (1) the savings to be achieved by Colonial Gas through the avoidance of a rate case during the ten–year rate freeze, and (2) Colonial Gas' revenue requirement at the end of the rate freeze had it operated on a stand-alone basis during that period. D.T.E. 98-128, at 9, 65. The savings to be achieved is the difference between Colonial Gas' stand-alone revenue requirement and Colonial Gas' cost of service as a merged company after the rate freeze. D.T.E. 98-128, at 9.

Subsequent to the Eastern-Colonial Gas merger, there were two other mergers affecting Colonial Gas. In 2000, KeySpan acquired Eastern; in 2007, KeySpan merged with National Grid. The Department must determine the appropriate effect of these mergers on the calculation of the merger savings allowance in this case.

We have found above that National Grid correctly determined that $123,948,607 represents Colonial Gas' stand-alone revenue requirement at the end of the ten-year rate freeze. According to National Grid, Colonial Gas' net cost of service prior to the application of the merger savings is $113,073,750 (Exh. NG-MDL-6-Colonial (Rev. 3) at 1). Accordingly, National Grid calculates the merger savings, which is the difference between $123,948,607 and $113,073,750, as equal to $10,874,857 (Exh. NG-MDL-6-Colonial (Rev. 3) at 1).[265] The Attorney General argues, however, that National Grid's calculation of merger savings fails to

[265] As previously noted, National Grid grossed up this amount by a bad debt factor of 1.82 percent increasing the savings to $11,080,351, which represents National Grid's proposed merger savings allowance to be recovered in rates (Exh. NG-MDL-6-Colonial Gas (Rev. 3) at 1). We will address this matter below.

incorporate reductions in its current revenue requirements that have resulted from the KeySpan acquisition of Eastern and the National Grid-KeySpan merger (Attorney General Brief at 95).

For the reasons discussed below, we find that National Grid has failed to demonstrate that its calculation of merger savings is attributable solely to the merger approved in D.T.E. 98-128. Colonial Gas' cast-off cost of service as approved in D.T.E. 98-128 was based on a 1997 test year, adjusted for specific post-test year changes. D.T.E. 98-128, at 21-53. Therefore, any cost savings from mergers that occurred during the period from the test year in D.T.E. 98-128 to the test year in the instant docket would have been incorporated in Colonial Gas' filed cost of service. See D.P.U. 09-39, at 276-278. The 2000 acquisition of Eastern by KeySpan and the 2007 acquisition of KeySpan by National Grid occurred during the term of Colonial Gas' rate freeze. Thus, if we were to accept that National Grid's savings amount of $10,874,857 is solely attributable to the Eastern-Colonial Gas merger, it would presume that there were no savings from the subsequent two mergers. This interpretation is untenable, inconsistent with our overall findings in D.T.E. 98-128, and not in the public interest.

It is well-recognized that cost savings arising from merger activities may be considered by the Department. D.P.U. 09-39, at 275; Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A D.P.U. 08-43, at 45. The Department's Order in D.P.U. 98-128, at 92 allowed Colonial Gas an opportunity to collect the costs of the Eastern-Colonial Gas merger (up to a $12.3 million annually) so long as the company could demonstrate that savings related to this merger were realized during the ten-year rate freeze to offset the cost sought for recovery through rates (see Exh. DPU-1, at 26). Accordingly, pursuant to our Order in

D.P.U. 98-128, National Grid has the burden to demonstrate that there were savings related to the Eastern-Colonial Gas merger that occurred during the ten-year rate freeze. It is not appropriate for National Grid to include the savings that result from two later, unrelated mergers in its calculations used to offset the Eastern-Colonial gas merger-related costs that it now seeks to recover in rates.

National Grid argues that it is not appropriate to account for the costs of these later mergers because the Department's Order in D.P.U. 98-128 does not make explicit provision for such in the tracking mechanism used to calculate merger related savings. However, neither the Rate Plan nor the tracking mechanism approved in D.T.E. 98-128 provide that in the process of demonstrating the actual cost of service for Colonial Gas at the end of the rate freeze period, savings from other intervening and unrelated mergers are to be excluded from consideration in determining the merger savings allowance.

The tracking mechanism approved in that case was designed to measure the amount of savings from the Eastern-Colonial Gas merger. Absent the subsequent mergers that occurred during the rate freeze, National Grid's application of the tracking mechanism would result in an appropriate calculation of savings related to the Eastern-Colonial Gas merger. Here, however, in order to calculate the amount of savings solely related to the Eastern-Colonial Gas merger, we find that it is necessary to make specific adjustments to Colonial Gas' 2009 test year cost of service by adding back savings from the KeySpan-Eastern and National Grid-KeySpan mergers. Such adjustments are necessary to ensure that costs related to the Eastern-Colonial Gas merger that the Companies seek to recover in rates are appropriately offset by savings realized solely from the Eastern-Colonial Gas merger and that the resulting merger savings adjustment results in just and reasonable rates.

The Attorney General calculates $3.0 million in combined savings from the KeySpan-Eastern and KeySpan-National Grid mergers (Attorney General Reply Brief at 36, 38, citing Exhs. AG-1-28, Att. (I) (2), at 3; AG-22-2; AG-25-6). To account for the $3.0 million in combined savings, the Attorney General proposes to make specific adjustments to Colonial Gas' 2009 test year cost of service by adding back $1,238,269 savings from the KeySpan-Eastern merger as well as $1,810,400 from the KeySpan-National Grid merger, in order to isolate those merger-related savings from the final determination of Colonial Gas' merger savings pursuant to the tracking mechanism approved in D.T.E. 98-128 (Attorney General Reply Brief at 38-39, citing Exhs. AG-1-28, Att. (I) (2), at 3; AG-22-2; AG-25-6).

With respect to the Attorney General's quantification of merger savings of $1,238,269 from the KeySpan-Eastern merger, she determined this amount by multiplying the estimated annual KeySpan-Eastern merger savings of $40 million by an allocator of 3.10 percent, derived from National Grid's "3-Point Allocator (KeySpan Companies)" (Exhs. AG-LS-2, at 2, citing Exhs. AG-1-28, Att. (I) (2) at 3; AG-22-2). The basis for the $40 million annual cost savings is KeySpan Corporation's March 30, 2001 Form 8K filing to the SEC, which states: "We expect annual pre-tax cost savings of approximately $40 million, resulting from the elimination of duplicate corporate administrative programs and operating efficiencies" (Exh. AG-22-2, at 1).[266]

National Grid does not contest this number other than to argue that: (1) the terms of the Rate Plan in D.T.E. 98-128 do not contemplate, require, or imply that merger savings from future mergers should be accounted for in the tracking mechanism; and (2) there is no evidence in the record that any of this amount is related to Colonial Gas or that the savings were actually achieved (National Grid Brief at VII.13; National Grid Reply Brief at 73). Further, National Grid did not provide an alternative amount. As we stated above, it is the Companies' burden to demonstrate that the savings calculated as $10,874,857 are solely attributable to the Eastern-Colonial Gas merger. The Companies have failed to do so. Accordingly, the Department could reject the total amount of savings proposed by the Companies. Here, however, the Attorney General has presented a quantification of the savings from the KeySpan-Eastern merger based on record evidence (Exhs. AG-LS-2, at 2; AG-1-28, Att. (I) (2) at 3; AG-22-2). Accordingly, we accept the Attorney General's proposed amount of $1,238,269 and use of the 3-Point Allocator for purposes of determining Colonial Gas' share of savings attributable to the Eastern-Keyspan merger.

In the case of the estimated merger savings of $1,810,400 from the National Grid-KeySpan merger, the Attorney General determined this amount by multiplying the annual National Grid-KeySpan merger savings estimate for 2009 of $124,000,000 by a 1.46 percent

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266 The KeySpan-Eastern merger did not require regulatory approval in any jurisdiction (Exh. AG-22-2, at 1).

allocator designed to reflect Colonial's share of the total savings[267] (Exhs. AG-LS-2, at 2, citing Exhs. AG-1-28, Att. (I)(2) at 3; AG-22-2). The record shows that the savings achieved for the calendar year 2009 were calculated to be $124,000,000 (Exh. AG-25-6). Further, we find that use of a 1.46 percent allocator is appropriate in this instance. Accordingly, we find that the annual merger savings related to the National Grid-KeySpan merger are $1,810,400.

e. Ratemaking Treatment of Goodwill

An acquisition premium is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions, D.P.U. 93-167-A at 9 (1994). While the Department has not traditionally recognized those premiums for ratemaking purposes, the Department will consider, on a case-by-case basis, individual merger or acquisition proposals that seek recovery of an acquisition premium, as well as the recovery level of such premiums. NIPSCO-Bay State Acquisition, D.T.E. 98-31, at 38 (1998); D.T.E. 98-27, at 61; D.P.U. 93-167-A at 18-19. Under the Department's standard, a company proposing a merger or acquisition must, as a practical matter, demonstrate that the costs or disadvantages of the transaction are accompanied by benefits that warrant their allowance. D.T.E. 98-31, at 38; D.T.E. 98-27, at 61; D.P.U. 93-167-A at 18-19. Thus, allowance or disallowance of an acquisition premium is but one component of the cost/benefit analysis involved in a merger or acquisition.

267 The 1.46 percent allocator was derived from National Grid's "3-Point Allocator G51 (All NGrid and KeySpan Companies)" (Exh. AG-1-28(I)(2), Att. 3 at 3).

In approving the Eastern-Colonial Gas merger, the Department noted that Eastern will pay Colonial Gas' shareholders $199.2 million over book value, or acquisition premium, to acquire Colonial Gas' distribution business. D.T.E. 98-128, at 91. The Department also noted that the petitioners in that docket proposed to use "purchase accounting" for the transaction and to record the acquisition premium on Colonial Gas' books, amortized over a 40-year period, resulting in a $5.0 million per year charge against Colonial Gas' earnings. D.T.E. 98-128, at 92. In addition, the Department noted that because this charge is not tax-deductible, the petitioners proposed to apply a tax factor of 1.6454 to achieve sufficient after-tax earnings to cover the annual charge, thereby resulting in total pre-tax costs for the acquisition premium of $8.2 million per year. D.T.E. 98-128, at 92.

The issue that the Department must resolve here relates to the ratemaking treatment of the $8.2 million annual amortization of the $199.2 acquisition premium or goodwill paid by Eastern to acquire Colonial Gas in D.T.E. 98-128.[268] As noted above, this $8.2 million is one of the two components of the $12.3 million capped amount of the merger savings allowance that could be used to offset the costs of Eastern's acquisition of Colonial Gas. The Attorney General claims that because National Grid no longer amortizes goodwill because of a change in accounting rules, the Department should exclude the $8.2 million annual amortization established in D.T.E. 98-128 in determining Colonial Gas' cost of service (Attorney General

[268] The Department has long considered that neither financial nor tax accounting standards automatically dictate ratemaking treatment. Boston Edison Company, D.P.U./D.T.E. 97-95, at 76-77 (2001); Massachusetts-American Water Company, D.P.U. 95-118, at 107 (1996); NYNEX Price Cap, D.P.U. 94-50, at 305 (1995); Massachusetts Electric Company, D.P.U. 92-78, at 79-80 (1992); Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979).

Reply Brief at 40-41). However, National Grid contends that in D.T.E. 98-128, the Department expressly allowed the recovery of merger related costs on the condition that merger related savings can be demonstrated, not on the basis of the accounting treatment afforded to the resulting asset recorded on its books at any time following the acquisition and the payment of funds to acquire the assets (National Grid Reply Brief at 75, citing D.T.E. 98-128, at 91-96). National Grid adds that it actually incurred the $199.2 goodwill cost and that the Order in D.T.E. 98-128 expressly provided for recovery of the equivalent annual amortization provided that merger-related savings were demonstrated (National Grid Brief at VII.14, citing D.T.E. 98-128, at 91-96; National Grid Reply Brief at 75, citing D.T.E. 98-128, at 95-96).

The record demonstrates that in 2000 and 2001, National Grid amortized the acquisition premium, or goodwill, relating to the Eastern-Colonial Gas merger in the amounts of $6,575,860 and $9,366,010, respectively (Exh. AG-21-6). On January 1, 2002, National Grid adopted the Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142") and accordingly ceased amortization because, under SFAS 142, goodwill is no longer allowed to be amortized on a straight-line basis (Exhs. AG-21-6; DPU-AG-2-5, Att. at 12; Tr. 19, at 2782).

APB Opinion No. 17, Intangible Assets ("Opinion 17"), the financial accounting standard prior to SFAS 142, allowed the amortization of goodwill and "mandated an arbitrary ceiling of 40 years for that amortization" (Exh. DPU-AG-2-5, Att. at 6, citing Opinion 17). The first among a number of reasons listed for this change in SFAS 142 is that:

> Acquiring entities usually integrate acquired entities into their operations, and thus the acquirers' expectations of benefits from the resulting synergies usually are reflected in the premium that they pay to acquire those entities. However, the transaction-based approach to accounting [or purchase accounting] for goodwill under Opinion 17 treated the acquired entity as if it remained a stand-alone entity rather than being integrated with the acquiring entity; as a result, the portion of the premium related to expected synergies (goodwill) was not accounted for appropriately. This Statement adopts a more aggregate view of goodwill and bases the accounting for goodwill on the units of the combined entity into which an acquired entity is integrated . . . .

(Exh. DPU-AG-2-5, Att. at 5-6).

The above-cited reason for eliminating the fixed amortization of goodwill primarily relates to recognition by the financial community that a more aggregate view of goodwill as an intangible asset was necessary, given the changes in the financial capital market where intangible assets are becoming an increasingly important economic resource and are an increasing proportion of assets acquired. Such a change in accounting standards does not invalidate or nullify the $199.2 million paid by Eastern to Colonial Gas' shareholders. See D.T.E. 98-128, at 91. In addition, that amount remains on Colonial Gas' balance sheet (Exh. AG-1-2, Att. (8), at 1726-1786; Tr. 19, at 2777-2779). Based on the above considerations, we conclude that such a change in the financial accounting standard, as reflected in SFAS 142, does not require the exclusion of the $8.2 million annual amortization established in D.T.E. 98-128 in determining Colonial Gas' cost of service.

f. Conclusion

After due consideration and review of National Grid's proposal relating to Colonial Gas' merger savings allowance, the Department finds that the appropriate merger savings allowance is $7,826,188. With the adjustments addressed herein related to the revenue requirement for Colonial Gas, we find that application of the merger savings allowance will result in just and reasonable rates. Accordingly, the Department will reduce Colonial Gas' proposed cost of service by $3,048,669.[269]

Q. Amortization Expense

1. Introduction

During the test year, National Grid booked amortization expense associated with leasehold improvements and computer software as follows: (1) $3,373,290 to Boston Gas-Essex Gas; and (2) $330,132 for Colonial Gas (Exhs. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas (Rev. 3) at 6, 37; NG-MDL-2-Colonial Gas (Rev. 3) at 6, 36). National Grid adjusted these amounts to reflect correcting entries recorded in February 2009 that reversed previously recorded amortization expenses related to the Companies' computer software system (Exhs. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas WP 13, at 7; NG-MDL-2-Colonial Gas WP 10, at 6; Tr. 8, at 1104; Tr. 14, at 2020-2023). These adjustments totaled $4,272,005 for Boston Gas-Essex Gas and $1,169,690 for Colonial Gas (Exhs. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas (Rev. 3) at 6; NG-MDL-2-Colonial Gas (Rev. 3) at 6). Thus, the resulting adjusted test year amortization expenses total

[269] As part of its proposed merger savings calculation, National Grid grossed up the merger savings by 1.82 percent to allow for uncollectible expense (Exh. NG-MDL-6 Colonial Gas (Rev. 3) at 1). The Department's calculation of uncollectible expense relies on an iterative process using the total allowed distribution revenue requirement and does not disaggregate distribution-related uncollectible expense by particular expense categories. See Section X.L, below; D.P.U. 09-39, at 164. Because the Department's calculation method ensures that Colonial Gas will recover uncollectible expenses associated with the merger savings expense, the Department will not gross up the merger savings expense for uncollectible expense.

$7,645,295 and $1,499,822 for Boston Gas-Essex Gas and Colonial Gas, respectively (Exh. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas (Rev. 3) at 6, 37; NG-MDL-2-Colonial Gas (Rev. 3) at 6, 36).

National Grid calculated the rate year level of amortization expense by annualizing the adjusted actual amortization expense recorded for the month of December 2009 that related to leasehold improvements and computer software (Exhs. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas (Rev. 3) at 37; NG-MDL-2-Colonial Gas (Rev. 3) at 36). National Grid calculates a rate year expense of $6,707,880 for Boston Gas-Essex Gas and a rate year expense of $1,266,000 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 6, 37; NG-MDL-2-Colonial Gas (Rev. 3) at 6, 36). These calculations result in a reduction to the revised test year cost of service of Boston Gas-Essex Gas of $937,415 and reduction to the revised test year cost of service of Colonial Gas of $233,822 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 6, 37; NG-MDL-2-Colonial Gas (Rev. 3) at 6, 36). No party commented on the proposed adjustments.

2. Analysis and Findings

The Department has found that software costs are a routine and continuing part of a company's business, and that these expenses are recurring in nature. D.P.U. 07-71, at 119-120; D.P.U. 92-111, at 67; D.P.U. 89-114/90-331/91-80 Phase One at 152-153. At the same time, the Department will adjust test year expense levels for known and measurable changes to the test year. D.P.U. 87-260, at 75; D.P.U. 1270/1414, at 33.

The Department has examined National Grid's proposed adjustments to test year cost of service relating to amortization expense for Boston Gas-Essex Gas and Colonial Gas. The Department finds that test year amortization expense was appropriately adjusted to correct the erroneous amortization of the software system (Exhs. NG-MDL-1, at 42, 77; NG-MDL-2-Boston Gas (Rev. 3) at 6, 37; NG-MDL-2-Colonial Gas (Rev. 3) at 6, 36; NG-MDL-6-Boston Gas WP 13, at 7; NG-MDL-2-Colonial Gas WP 10, at 6; Tr. 14, at 2020-2023). Further, the Department finds that the proposed amortization expense is a representative level of test year expense. Accordingly, the Department accepts National Grid's proposed amortization expense adjustments.

R. Property Taxes

1. Introduction

During the test year, property tax expense associated with utility property was booked as follows: (1) $21,729,057 to Boston Gas-Essex Gas, and (2) $4,553,888 to Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 38-39; NG-MDL-2-Colonial Gas (Rev. 3) at 37-38). National Grid proposes to increase the test year cost of service of Boston Gas-Essex Gas by $4,694,514 and to increase the test year cost of service of Colonial Gas by $457,411 for property tax expense (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 38-39; NG-MDL-2-Colonial Gas (Rev. 3) at 37-38).[270] The proposed adjustments are based on updated property tax information, which National Grid provided to the Department at the close of the record in

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270 The proposed pro forma adjustment to the cost of service of Boston Gas-Essex Gas also appropriately takes into account the removal of $173,761 for property taxes associated with non-utility property and property held for future use (Exhs. NG-MDL-1, at 44; NG-MDL-2-Boston Gas (Rev. 3) at 39).

this proceeding (Exhs. NG-MDL-1, at 44, 78; NG-MDL-3-Boston Gas (Rev. 3); NG-MDL-3-Colonial Gas (Rev. 3)). No party commented on the proposed adjustments.

2. Analysis and Findings

The Department's general policy is to base property taxes on the most recent property tax bills a utility receives from communities in which it has property. D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 109; D.P.U. 86-280-A at 7, 17; D.P.U. 84-94, at 19. Based on the most recent municipal tax billings provided by the Companies, annualized municipal tax expense for Boston Gas-Essex Gas totals $26,423,571 (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 39; NG-MDL-3-Boston Gas (Rev. 3)). The annualized municipal tax expense for Colonial Gas totals $4,991,299 (Exhs. NG-MDL-2-Colonial Gas (Rev. 3) at 38; NG-MDL-3-Colonial Gas (Rev. 3)).

The Department has reviewed the property tax expense calculations submitted by National Grid, as well as the invoices supporting these calculations (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 38-39; NG-MDL-3-Boston Gas; NG-MDL-3-Boston Gas (Rev. 3); NG-MDL-2-Colonial Gas (Rev. 3) at 37-38; NG-MDL-3-Colonial Gas; NG-MDL-3-Colonial Gas (Rev. 3)). The Department is satisfied that National Grid has properly accounted for non-utility operations in the calculation of the Companies' municipal tax expense (Exhs. NG-MDL-1, at 44; NG-MDL-2-Boston Gas (Rev. 3) at 39). Further, we are satisfied that National Grid's remaining calculations of property tax expense are appropriately supported by the record (Exhs. NG-MDL-3-Boston Gas; NG-MDL-3-Boston Gas (Rev. 3);

NG-MDL-3-Colonial Gas; NG-MDL-3-Colonial Gas (Rev. 3)). Accordingly, the Department accepts National Grid's proposed property tax expense adjustments.

S. Attorney General Consultant Expenses Tariff

1. Introduction

Pursuant to G.L. c. 12, § 11E(b), the Attorney General may retain experts or other consultants to assist her in Department proceedings involving rates, charges, prices, and tariffs of an electric, gas, generator, or transmission company subject to the Department's jurisdiction. The cost of retaining such experts or consultants cannot exceed $150,000 per proceeding, unless otherwise approved by the Department based upon exigent circumstances. G.L. c. 12, § 11E(b). All reasonable and proper expenses for such experts or consultants are to be borne by the affected company and are recoverable through the company's rates without further approval by the Department. G.L. c. 12, § 11E(b).

In this case, the Department authorized the Attorney General to expend up to $400,000 for outside experts and consultants due to exigent circumstances (i.e., the complexity of the instant rate case filing, compounded by the existence of three separate distribution companies, the presentation of multiple sets of consolidated rates, a proposed TIRF, and proposed revenue decoupling mechanism). D.P.U. 10-55, Order on Attorney General's Notice of Retention of Experts and Consultants at 5-6 (May 27, 2010). National Grid reports that the fees related to the Attorney General's experts and consultants total $89,817, as of August 5, 2010, and additional fees are expected to be incurred (RR-DPU-113).[271]

2. National Grid's Proposal

National Grid proposes to include a factor in its LDAC to recover the Attorney General's consultant expenses ("AGCE") (Exh. NG-AEL-4, at 34, 39). The factor is designed to recover the AGCE from all customers based on annual throughput (Exhs. NG-AEL-4, at 48-49; DPU-18-12). The Companies' customers will all pay the same per unit charge (Exh. DPU-18-12). National Grid proposes to apply the same rate of interest on unrecovered balances for the AGCE as it does for all LDAC reconciling mechanisms, which is the prime lending rate (Exhs. NG-AEL-4, at 60-61; DPU-18-13). National Grid states that information pertaining to these expenses will be filed with the Department consistent with the filing requirements of all costs and revenue information included in the LDAC (Exh. NG-AEL-4, at 65-66). No party commented on National Grid's proposal.

3. Analysis and Findings

In authorizing the Attorney General to expend up to $400,000 for outside experts and consultants in this proceeding, the Department did not address the merits of National Grid's proposed recovery mechanism, stating that this issue would be addressed during the course of the instant rate proceeding. Boston Gas Company et al., D.P.U. 10-55, Order on Attorney

271 Though required to do so (see Tr. 20, at 2949), National Grid failed to provide an update of these expenses on August 30, 2010, or at the close of the evidentiary record on September 24, 2010. In future filings, we expect all electric and gas distribution companies to provide timely updates of rate case-related expenses, including expenses such as these that are collected through a reconciling mechanism.

General's Notice of Retention of Experts and Consultants at 6 (May 27, 2010). The Department has broad discretion in selecting an appropriate rate recovery mechanism. See American Hoechest Corp. v. Department of Public Utilities, 379 Mass. 408, 411-413 (1980) (the Department is free to select or reject particular method of regulation as long as choice not confiscatory or otherwise illegal).

General Laws c. 12, § 11E(b) requires that all reasonable and proper expenses for the Attorney General's experts or consultants are recoverable through the company's rates without further approval by the Department. National Grid's proposed recovery mechanism achieves this result. The LDAC allows National Grid to recover, on a fully reconciling basis, costs that have been determined to be distribution-related but, because they are reconciling, are more appropriately recovered outside base rates. See D.T.E. 98-27, at 6-7 n.9.[272] Further, the LDAC is applicable to all firm customers, i.e., both sales and transportation customers. D.T.E. 98-27, at 6-7 n.9. As such, we conclude that National Grid's proposal to recover the AGCE through its LDAC is reasonable and appropriate and, thereby, approved.[273]

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[272] The Department has approved the recovery of AGCE through a company's LDAC in recent cases. See The Berkshire Gas Company, D.P.U. 10-GAF-02 (2010); D.P.U. 09-30, at 408.

[273] As we gain more experience with these types of expenses, we will consider whether these expenses are better recovered through base rates instead of in a reconciling mechanism.

T. Promotional and Advertising Expense

1. Introduction

During the test year, Boston Gas-Essex Gas booked $644,976 and Colonial Gas booked $106,923 in direct expenses associated with customer incentive programs and rebates (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8). These expenses are direct expenses associated with sales promotions such as charges for heating equipment and rebates provided to new heating customers (Exh. NG-MDL-1, at 17).

As required by Department precedent, National Grid removed from its promotional expense those costs that were related to electric-to-gas customer conversions (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8; Bay State Gas Company, D.P.U. 05-27-A at 30-31 (2007); D.P.U. 05-27, at 219-220 (2005); D.P.U. 03-40, at 251-252; see also G.L. c.164, § 33A. The Companies derived these adjustments by multiplying their respective test year promotional expenses by the test year percentage of electric conversions to total conversions (Exhs. NG-MDL-1, at 17, 60; NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8). Based on a test year percentage of electric-to-gas conversion of 1.07 percent for Boston Gas-Essex Gas and 3.5 percent for Colonial Gas, National Grid removed $6,901 from Boston Gas-Essex Gas' test year cost of service, along with $3,742 from Colonial Gas' test year cost of service (Exh. NG-MDL-1, at 17, 60; NG-MDL-2-Boston Gas (Rev. 3) at 8, 9; NG-MDL-2-Colonial Gas (Rev. 3) at 8, 9; Tr. 8, at 1136, 1140). As a result of these adjustments, National Grid has proposed to include in cost of service $638,075 and $103,181 in customer incentive programs and rebate expense for Boston Gas-Essex Gas and Colonial Gas, respectively (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8).

In addition, Boston Gas-Essex Gas and Colonial Gas booked $2,046,931 and $407,807 in advertising expense, respectively, during the test year (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8). National Grid removed $156,995 in Boston Gas-Essex Gas' advertising costs related to the April 2008 water main break in the City of Boston (discussed in Section X.I, above), along with $6,493 in merger-related advertising and $1,434,464 in other advertising costs identified as image-related, promotional, or otherwise deemed as not being recoverable through rates (Exhs. NG-MDL-1, at 17; NG-MDL-2-Boston Gas (Rev. 3) at 8, 9; Tr. 8, at 1135-1136, 1140). For Colonial Gas, National Grid removed $1,447 in merger-related advertising and $309,908 in other advertising costs identified as image-related, promotional, or otherwise deemed as not being recoverable through rates (Exhs. NG-MDL-1, at 59-60; NG-MDL-2-Colonial Gas (Rev. 3) at 8, 9; Tr. 8, at 1135-1136, 1140). As a result of these adjustments, National Grid has proposed to include in cost of service $448,979 and $96,452 in advertising expense for Boston Gas-Essex Gas and Colonial Gas, respectively (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-2-Colonial Gas (Rev. 3) at 8). No party addressed these issues.

2. Analysis and Findings

a. Promotional Expense

To recover promotional expenses through base rates, a company must demonstrate that the program results in net benefits to ratepayers. D.T.E. 01-56, at 67; D.P.U. 92-111, at 193.

The measurement of net benefits is dependent upon the particular ratemaking treatment to be accorded to the program. Where the utility seeks to include the program above the line for ratemaking purposes, an incremental approach is used because ratepayers would receive the benefit of any incremental profitability. D.P.U. 90-121, at 35; D.P.U. 87-122, at 20. If a utility seeks to place the program below the line for ratemaking purposes, a portion of common or indirect costs must be assigned to the program because ratepayers are supporting the cost of utility resources being used in part to support the program. See D.P.U. 87-59, at 6-10. Whatever ratemaking treatment may be proposed for a promotional program, the cost analysis should appropriately include both direct and indirect expenses so that both the economic benefits of the program and the appropriate ratemaking treatment can be determined. See D.T.E. 01-56-A at 16-17.

Boston Gas' promotional program has previously been the subject of Department inquiry. D.T.E. 03-40, at 227-254. In that case, the Department stated that we will allow rate recovery of representative costs associated with a gas company's marketing or promotional programs if the evidence demonstrates that: (1) existing gas customers have received a net benefit from expansion of the system shown to be the result of the marketing or promotional program; and (2) expenditure at that level will likely continue, given the company's intent to continue such programs, the economic circumstances prevailing in the gas industry (as compared to competing fuels) when new rates are set, and the likelihood that such programs will continue to provide comparable benefits to existing ratepayers over the years or the term such new rates will be in effect. D.T.E. 03-40, at 249. The Department, however, required that all companies seeking recovery of promotional program costs must present an internal rate of return analysis that: (1) excludes extraneous factors, such as growth-related capital projects; (2) is conducted program-by-program; (3) includes all indirect promotional expenses; and (4) is conducted on both a pre and post-implementation basis. D.T.E. 03-40, at 249.

National Grid has not conducted an internal rate of return analysis on its promotional programs, although the Companies have submitted some customer conversion data that was used to derive their electric-to-gas conversion ratios (Exhs. NG-MDL-6 Boston Gas WP 12; NG-MDL-8 Colonial Gas WP 9). While the workpapers contain other data on what appears to be associated throughput volumes and revenues, it is not intuitive whether the data relate to throughput or other aspects of the Companies' conversion programs, such as total allocated costs. National Grid has the burden to demonstrate that it has met the Department's established standards for the recovery of promotional expenses. Even if the Department were to view this supporting documentation in the light most favorable to National Grid, the data contained therein are insufficient to permit the Department to make required findings on the factors identified in D.P.U. 03-40, at 249, such as the exclusion of growth-related capital projects, a program-by-program evaluation, the inclusion of all indirect promotional expenses, or analyses on a pre- and post-implementation basis.

Because National Grid has not conducted the type of evaluation required by the Department in D.T.E. 03-40, at 249, we are unable to conclude that the Companies' customer promotional program expenditures are reasonable, cost-effective, and provide net benefit to ratepayers. Therefore, as National Grid has failed to meet its burden of proof on these issues, the Department will reduce Boston Gas-Essex Gas' proposed cost of service by $638,075, and will reduce Colonial Gas' proposed cost of service by $103,181.

b. Advertising Expense

Pursuant to G.L. c. 164, § 33A, gas or electric companies may not recover from ratepayers direct or indirect expenditures relating to promotional advertising. D.P.U. 92-210, at 98; Bay State Gas Company, D.P.U. 92-111-A at 8. Exempt from this provision, however, is advertising "which relates to any explanation or justification of existing or proposed rate schedules, or notification of hearings thereon which informs consumers of and stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the [D]epartment or any other government agency." G.L. c. 164, § 33A.

In order to facilitate the review of utility advertising, the Department has established four primary groupings: (1) image-related; (2) informational; (3) promotional; and (4) miscellaneous.[274] D.P.U. 96-50 (Phase I) at 64; D.P.U. 92-111, at 182-191; D.P.U. 90-121, at 130-136. The Department further separates the promotional class into the following: (1) advertising that promotes the use of gas explicitly in competition with an unregulated fuel; (2) advertising that promotes the use of gas but does not explicitly reference an unregulated fuel; and (3) advertising that promotes non-utility operations. D.P.U. 93-60, at 162. In this context, the term "explicitly" as applied to competition with an unregulated fuel

[274] The Department recognizes additional advertising categories, such as political advertising, which is explicitly precluded from rate recovery under G.L. c. 164, § 33A, and conservation-related advertising, which is permitted. D.P.U. 92-210, at 99 n.56.

means that the advertisement must leave the reader or listener with the reasonable impression that the target of the advertisement is an unregulated fuel. D.P.U. 90-121, at 133.[275]

As does the Department, National Grid categorizes advertising expenses into four groupings: image-related, informational, promotional, and miscellaneous expenses (Tr. 8, at 1142; RR-DPU-48). The Companies also have provided copies of their advertising materials (Exhs. NG-MDL-6-Boston Gas WP 15; NG-MDL-8-Colonial Gas WP 12). Thus, National Grid has categorized its advertising expense so as to allow the Department to review these expenditures in an orderly and efficient manner.

National Grid seeks recovery of advertising expenses in the amount of $448,979 for Boston Gas-Essex Gas and $96,452 for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 8; NG-MDL-6-Boston Gas WP 15; NG-MDL-2-Colonial Gas (Rev. 3) at 8; NG-MDL-8-Colonial Gas WP 12). Boston Gas-Essex Gas' proposed advertising expense consists of: (1) $65,823 in informational advertising; (2) $359,214 in promotional advertising; and (3) $23,940 in miscellaneous advertising (Exh. NG-MDL-2-Boston Gas WP 15, at 1-4). Colonial Gas' proposed advertising expense consists of: (1) $14,789 in informational advertising; (2) $76,196 in promotional advertising; and (3) $5,472 in miscellaneous advertising (Exh. NG-MDL-2-Boston Gas WP 12 at 1-4). The Department has examined the supporting documentation for the Companies' proposed advertising expense, including the

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275 The Department has long-recognized the difficulties associated with determining the eligibility of advertising expense for rate recovery. As we noted in D.T.E. 03-40, at 277, the review process is akin to "commanding haystacks to render up their needles."

advertising copy provided in their various workpapers (Exhs. NG-MDL-6-Boston Gas WP 15; NG-MDL-8-Colonial Gas WP 12).

As noted above, the Department denied recovery of the Companies' proposed promotional program costs because they failed to present data sufficient to permit the Department to conclude that such expenses are reasonable, cost-effective, and provide net benefit to ratepayers. D.P.U. 03-40, at 249. Because the Department has eliminated National Grid's promotional programs from cost of service, it is also appropriate to remove those associated advertising expenditures related to the Companies' promotional programs. D.P.U. 92-111, at 194-195. During the test year, Boston Gas-Essex Gas and Colonial Gas booked \$359,214 and \$76,196, respectively, to promotional advertising expense (Exhs. NG-MDL-6 Boston Gas WP 15 at 4; NG-MDL-6 Colonial Gas WP 12 at 4). Therefore, the Department will reduce Boston Gas-Essex Gas' proposed cost of service by \$359,214, and will reduce Colonial Gas' proposed cost of service by an additional \$76,196.[276]

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[276] Because the Department has excluded National Grid's entire promotional advertising expense from cost of service, a detailed discussion of the Companies' promotional advertising is unnecessary. Nevertheless, at least some of the Companies' proposed promotional expense may not have been eligible for recovery under G.L. c. 164, § 33A. For example, Invoice Number 2691 is for the purchase of 120 stuffed polar bears (Exh. NG-MDL-6-Boston Gas WP 15, at 316-317). The stuffed bears do not appear to be otherwise labeled, but appear to be associated with National Grid's "The Power of Action" campaign, which is intended to promote energy conservation. While the goals of this campaign may be laudable, the Department questions whether unlabeled stuffed polar bears are sufficiently differentiated from other commonly-available stuffed bears to represent recoverable advertising expense as defined by G.L. c. 164, § 33A. Also, National Grid's proposed promotional advertising expense includes costs associated with a Rhode Island trade ally's participation in a Rhode Island trade show (Exh. NG-MDL-6-Boston Gas WP 15, at 401). The Department

U. DriveCam

1. Introduction

NGSC recently implemented a driver safety program, the DriveCam's Driver Risk Management program ("DriveCam"), that monitors an employee's actual driving experience to reduce the number of traffic accidents involving National Grid's employees (Exhs. NG-WJA-1, at 17; UWUA-1-1, Att. (A)(3) at 1). The DriveCam technology consists of a palm-sized audio and visual recorder mounted inside each of National Grid's vehicles that continuously records events occurring both inside and outside the vehicle (Exhs. NG-WJA-1, at 17; UWUA-1-1, Att. (A)(2) at 10). Abrupt movements detected inside the vehicle, such as hard braking, sudden acceleration, swerving, or vehicle collisions trigger the recorder to save both a visual and an audio recording of the period covering the period of time from eight seconds before the event to four seconds after the event (Exhs. NG-WJA-1, at 17; UWUA-1-1, Att. (A)(2) at 10; UWUA-1-9; Tr. 4, at 392-393). The data are then transmitted to DriveCam's facilities, where they are reviewed and scored by DriveCam personnel (Exh. UWUA-1-1, Att. (A)(3) at 13, 15; Tr. 4, at 393; RR-NEGWA-12). If DriveCam determines that the incident was attributed to driver behavior, the results are sent to the driver's supervisors (Exh. UWUA-1-1, Att. (A)(3); Tr. 4, at 393).[277] Thereafter, National Grid takes appropriate actions, including driver coaching by the employee's supervisor, with the goal of

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does not consider this expense to be appropriately allocated to Massachusetts operations.

277 Since June 2009, over 200 DriveCam events have been recorded (Exh. UWUA-1-8).

addressing and correcting poor driving behaviors (Exh. UWUA-1-8). If the driver continues to engage in poor driving behavior, a progressive series of measures may be taken, including driver training, sanctions, and discipline as a final recourse (Exh. UWUA-1-8).

In late 2008, NGSC began examining the feasibility of DriveCam, beginning with a pilot study involving certain fleet vehicles in Providence, Rhode Island, and Brooklyn, New York (Exhs. UWUA-1-1, Att. (A)(2) at 4; UWUA-1-2). Using data generated by the pilot study, NGSC prepared a report in February 2009, which included various cost-benefit analyses (Exh. UWUA-1-1, Atts. (A)(1), (A)(2)).[278] According to the Companies, the cost-benefit analysis indicated annual savings ranging from $1.5 million to $2.8 million if DriveCam was installed on a system-wide basis (Exh. UWUA-1-1, Att. (A)(2) at 3).[279]

Consequently, NGSC entered into a contract with DriveCam in March 2009 (Exh. UWUA-2-1, Att. (A)). The first event recorders were activated on June 1, 2009, in fleet vehicles located at the Companies' Waltham and Commercial Point yards, and NGSC completed the installation of the DriveCam system throughout its gas distribution operations, including those of the Companies, by the end of March 2010 (Exh. UWUA-1-3; Tr. 4,

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278 In addition, NGSC reviewed a second, independent study performed by employees of the Virginia Tech Transportation Institute for the U.S. Department of Transportation's Federal Motor Carrier Safety Administration (Exh. UWUA-1-1, Att. (B)).

279 While DriveCam estimated that NGSC would experience annual savings of $2.8 million, the Companies' own analysis quantified annual savings at $1.5 million per year (Tr. 4, at 420).

at 394).[280] During the test year, Boston Gas-Essex Gas booked $370,168 in DriveCam expenses and Colonial Gas booked $70,490 in DriveCam expenses (RR-UWUA-2).

2. Positions of the Parties

a. UWUA

UWUA maintains that the costs of the DriveCam program are not justified on either economic or safety grounds (UWUA Brief at 3, 4). First, UWUA argues that the costs associated with DriveCam are not warranted on economic grounds (UWUA Brief at 3). In support of its position, UWUA notes that the Companies' annual savings estimate of $1.5 million is less than the break-even savings of $2.0 million per year identified in the cost-benefit study (UWUA Brief at 3, citing Exh. UWUA 1-1, Att. (A)(1) at 5; UWUA 1-1, Att. (A)(2) at 15). UWUA further notes that National Grid acknowledges that the investment in DriveCam produces a negative net present value over both a ten-year and a 20-year investment horizon (UWUA Brief at 3-4, citing Exh. UWUA 1-1, Att. (A)(2) at 3; Tr. 4, at 428).

Turning to National Grid's claims that DriveCam is justified for safety reasons, UWUA argues that, just as the Department requires that a capital addition to rate base be both (1) prudently incurred, and (2) used and useful before the addition may be included in rate base, the Companies must demonstrate the prudency of its decision to embark on the DriveCam program (UWUA Brief at 4, citing Fitchburg Gas and Electric Light Company v.

280 According to National Grid, there has been employee resistance to the installation of DriveCam, including legal concerns about the recorders' audio capabilities (Exhs. UWUA-1-1, Att. (A)(1) at 7; UWUA-2-6; Tr. 4, at 395).

Deptartment of Public Utilities, 375 Mass. 571, 578 (1978); Massachusetts-American Water Company, D.P.U. 95-118, at 39-42 (1996)). UWUA maintains that the Companies have failed to demonstrate the prudence of the DriveCam expenditures because the savings associated with safety are outweighed by the annual program expenditures (UWUA Brief at 4; UWUA Reply Brief at 2-3). Moreover, the UWUA maintains that the Companies' claims of improved safety attributed to DriveCam are overstated because these types of benefits are highly speculative and, as conceded even by National Grid, are likely to be unascertainable (UWUA Brief at 5). UWUA argues that the Companies are unable to provide any documented savings relative to DriveCam and are unlikely to be able to produce such evidence in the future (UWUA Brief at 5-6, citing Tr. 4, at 419).

UWUA disputes National Grid's argument that no adjustment to test year DriveCam expenses are warranted because they are insignificant in magnitude and fall within the ebb and flow of annual expenses (UWUA Reply Brief at 3). UWUA contends that, under the Companies' reasoning, utilities would be able to shield from Department review any expense that, in their sole opinion, is small (UWUA Reply Brief at 3). UWUA contends that this approach is contrary to public policy and that the Department should base its decision in this case on the evidentiary record (UWUA Reply Brief at 3).

In the alternative, UWUA proposes that the Department reduce the Companies' test year cost of service to remove what it considers to be non-recurring expenditures related to DriveCam (UWUA Brief at 6; UWUA Reply Brief at 3). According to UWUA, the Companies estimated that $250,000 out of an estimated $500,000, or half, of DriveCam expenses were non-recurring (UWUA Brief at 6 & n.4). Based on this ratio of non-recurring expenses applied to the Companies' actual test year DriveCam expenses of $440,657, UWUA argues that the Department should remove $220,329 from the Companies' proposed cost of service (UWUA Brief at 6-7, citing Exh. UWUA-1-5; UWUA Reply Brief at 3).

b. NEGWA

NEGWA supports the UWUA's proposed exclusion of DriveCam expenses from National Grid's cost of service (NEGWA Reply Brief at 6). NEGWA maintains that despite the lack of evidence of any safety benefit after two years of trials, National Grid still "plays the safety card" in an attempt to justify its DriveCam expenditures (NEGWA Reply Brief at 6). Despite this effort by the Companies, NEGWA contends that the benefit/cost ratio associated with the DriveCam monitoring devices is no greater than 0.75 (NEGWA Reply Brief at 6). NEGWA concludes that because the DriveCam program has a negative net present value, the Companies' decision to install the monitoring devices was imprudent and the devices are not used and useful (NEGWA Reply Brief at 6).

c. National Grid

National Grid contends that it has devoted significant resources to the task of evaluating and implementing the DriveCam initiative for public safety reasons (National Grid Brief at IX.39). The Companies contend that they have documented the reasons for embarking on the DriveCam project (National Grid Reply Brief at 117-118). Further, the Companies allege that they have shown that the expenses were neither unreasonable, imprudent, excessive, nor incurred in bad faith and, therefore, they should be included in its cost of service (National

Grid Reply Brief at 117-118, citing Boston Gas Company v. Department of Public Utilities, 387 Mass. 531, 539 (1982); New England Telephone and Telegraph Co. v. Department of Public Utilities, 360 Mass. 443, 483-84 (1971)).

The Companies maintain that while positive cost-benefit analysis may inform and support the Department's consideration of a cost of service expense, the Department has never required a showing of positive net savings as a prerequisite to rate recovery, particularly when the underlying expense is intended to protect public or employee safety (National Grid Reply Brief at 117, citing Boston Gas Company, D.P.U. 03-40 (2003)). National Grid argues that disallowance of the DriveCam costs solely on the basis of employee complaints would be a disincentive to the implementation of similar safety-related initiatives in the future (National Grid Brief at IX.39).

In addition, National Grid maintains that the DriveCam expenditures are but one part of a comprehensive approach being undertaken to increase safety and protect property (National Grid Reply Brief at 119). The Companies argue that although certain test year expenses may not be incurred in a future period, other related expenditures will be made (National Grid Reply Brief at 119). National Grid contends that the Department does not engage in "endless controversy" about the accounting results of annual revenues and expenses incurred in the course of ordinary business; rather, the Department focuses only on those expenses and revenues that may fall outside of the normal ebb and flow of a business cycle (National Grid Reply Brief at 120, citing Massachusetts Electric Company, D.P.U. 95-40, at 73-74 (1995)). National Grid maintains that full inclusion of test year DriveCam expense is appropriate, because the costs are insignificant and fall well within the ebb and flow of expenses that the Department has long recognized in the ratemaking process (National Grid Brief at IX.39; National Grid Reply Brief at 120).

3. Analysis and Findings

The DriveCam expenditures represent operating expenses, as distinct from a capital project eligible for inclusion in rate base. Nevertheless, because issues have been raised regarding the prudence of NGSC's decision to embark on the DriveCam program, the Department's standard of review for evaluating the prudence of plant additions is instructive here. See, e.g., Massachusetts-American Water Company, D.P.U. 95-118, at 42 (1996); aff'd Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 202-203 (2001).

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. See Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-82-A at 48 & n.45 (2010), citing D.P.U. 08-35, at 20-21; Milford Water Company, D.P.U. 08-5, at 12-13 (2008); Boston Edison Company, D.P.U. 906, at 160, 164-165 (1982); see, also, Attorney General v. Department of Public Utilities, 390 Mass. 208, 299 (1983). 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 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known or reasonably should have been known at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); Boston Gas Company, D.P.U. 93-60, at 35 (1993); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26-27 (1985).

Therefore, the Department's examination of the DriveCam expenditures will not be confined to merely determining whether a signed contract exists with DriveCam, but rather will include a review of the Companies' decision-making process relative to entering into the DriveCam agreement. We recognize that there are potentially intangible benefits associated with the DriveCam system, including increased safety (Exh. UWUA-1-1, Att. (A)(1) at 4). There may also be intangible costs such as those related to a loss of privacy. These types of benefits and costs are more difficult to quantify than those typically associated with utility capital projects but are nonetheless worthy of consideration. See Boston Gas Company, D.P.U. 03-40, at 39 (2003).

The Department has examined National Grid's decision to embark on the DriveCam project, including each of the Companies' cost-benefit analyses. National Grid examined three

DriveCam installation options: (1) installation on all vehicles ("Option 1"); (2) installation only on customer meter service vehicles ("Option 2"); and (3) installation only on those vehicles in those areas with the most driver accidents ("Option 3") (Exh. UWUA-1-1, Att. (A)(2) at 14; Tr. 4, at 410). While DriveCam provided savings estimates for each of these three options, National Grid's internal analyses reduced these savings by approximately 45 percent to arrive at what the Companies considered to be more supportable savings estimates (Exh. UWUA-1-1, Att. (A)(2) at 15-19; Tr. 4, at 419-420). The resulting analyses indicated small negative net present value calculations for Option 1 and Option 2, with positive net present value savings associated with Option 3 (Exh. UWUA-1-1, Att. (A)(2) at 14-19). National Grid chose Option 1 and installed DriveCam on all of its vehicles (Tr. 4, at 415-416, 422).

National Grid estimated that the installation of DriveCam would reduce the current average accident cost per vehicle by 40 to 50 percent, and reduce damage claims and workers compensation expenses by 30 to 50 percent (Exh. UWUA-1-1, Att. (A)(2) at 3; Tr. 4, at 424). Other utilities that have implemented DriveCam have reported reductions in "responsible traffic accidents"[281] ranging from 35 to 60 percent (Exh. UWUA-1-1, Att. (A)(2) at 11-12; Tr. 4, at 421-422). While reductions in worker compensation claims and vehicle repairs were noted, these other utilities' support for DriveCam tended to be based on safety benefits (Exh. UWUA- 1-1, Att. (A)(2) at 11-12). National Grid's own pilot tests in Brooklyn and

281 Responsible traffic accidents are those traffic accidents where the utility was deemed to be at fault (Exh. UWUA 1-1, Att. (A)(2) at 11).

Providence were consistent with these overall results, provided that the DriveCam program was accompanied by timely driver coaching (Exh. UWUA-1-1, Att. (A)(2) at 6-8, 13).

While National Grid's cost-benefit analyses indicated only net present value savings under Option 3 (i.e., installation on vehicles operating in areas with the most driver accidents), the results of this type of analysis would not necessarily be dispositive of the matter. Unlike the Companies' evaluation of whether to extend gas service to a particular customer, a business decision that involves public safety matters will, by its nature, involve intangible considerations that may not lend themselves to the type of quantification found in a service expansion proposal. As noted above, the installation of DriveCam offers intangible benefits in the areas of public and employee safety, as well as intangible costs in the form of decreased privacy. All of these factors must be taken into consideration here. Therefore, while cost-benefit analyses are highly useful in making safety-related business decisions, other factors should also be considered. On the basis of National Grid's cost-benefit analyses, the results of its pilot programs, the results achieved by other utilities, and a balancing of the intangible costs and benefits of DriveCam, the Department concludes that National Grid's decision to embark on the DriveCam program was prudent and reasonable.[282]

Turning to the actual DriveCam expenditures, the Department permits a company to include expenses in its cost of service if it can demonstrate that the expense is either annually or periodically recurring or, if non-recurring, is extraordinary in nature. Commonwealth

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282 In reaching this finding, the Department declines to comment on any underlying, privacy-related legal issues associated with DriveCam; those matters are best resolved through the collective bargaining process.

Electric Company, D.P.U. 89-114/90-331/91-80 Phase One at 152 (1991); Western Massachusetts Electric Company, D.P.U. 88-250, at 65-66 (1989); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983). National Grid claims that its test year DriveCam expense is within the ebb and flow of expenditures and, thus, should be allowed in its entirety. While year-to-year changes in expenditures may represent merely an ebb and flow of annual costs and not trigger further scrutiny, the Department has not accepted the proposition that a level of expenses below a certain threshold is somehow per se exempt from review. Western Massachusetts Electric Company, D.P.U. 957, at 42-44 (1982). Although the total DriveCam expense may not represent a significant percentage of National Grid's combined revenue requirement, nonetheless UWUA has raised the issue as to the propriety of including these costs in rates. Therefore, the Department will examine National Grid's test year DriveCam expenditures.

The Companies have acknowledged that a portion of their test year DriveCam costs are in the form of initial implementation and are thus nonrecurring (Exhs. UWUA-1-5; UWUA 2-1, Att. (A); RR-UWUA-2). Although National Grid maintains that these nonrecurring DriveCam expenses are merely representative of other types of costs related to safety initiatives, the Companies have not quantified the nature or amount of these additional prospective safety initiatives. Nevertheless, we recognize that the Companies were installing the DriveCam devices over the period from June 2009 through March 2010 (Exh. UWUA 1-3; Tr. 4, at 394). Thus, it would be appropriate to annualize the recurring test year expense so that a full twelve months of DriveCam expense is included in cost of service. D.P.U. 85-270, at 156-157 (1986).

National Grid provided the Companies' aggregate DriveCam expenditures for 2010, consisting of (1) $155,000 in one-time implementation costs; (2) $60,000 in ongoing installation and replacement costs; and (3) $210,000 in ongoing management costs (RR-UWUA-3). The Department has examined this information and accepts National Grid's representation that the $270,000 in ongoing DriveCam expenditures is a reasonable proxy for National Grid's ongoing DriveCam expense (RR-UWUA-3). The Department also finds that the costs included in RR-UWUA-3 represent a known and measurable change to test year cost of service. See D.P.U. 09-30, at 211; D.P.U. 08-35, at 108; Oxford Water Company, D.P.U. 88-171, at 13-14 (1989).

Although the information in RR-UWUA-3 is not disaggregated by individual company, during the test year approximately 84 percent of the Companies' aggregate DriveCam expense was attributed to Boston Gas-Essex Gas, and the remaining approximately 16 percent was attributed to Colonial Gas (RR-UWUA-2). The Department finds that these ratios are reasonable for purposes of allocating the combined DriveCam expenses among Boston Gas-Essex Gas and Colonial Gas. See Bay State Gas Company, D.T.E. 05-27-A at 28 (2007).

Application of these respective ratios to the combined level of allowable DriveCam expense produces a DriveCam expense of $226,800 for Boston Gas-Essex Gas, and $43,200 for Colonial Gas. Accordingly, the Department will reduce the cost of service of Boston Gas-Essex Gas by $143,368, and will reduce the cost of service of Colonial Gas by $27,290.

V. Vehicle Leases

1. Introduction

During the test year, the Companies incurred costs related to the lease of five vehicles assigned to the Companies' officers (Exh. AG-1-37 (Supp.)). The annual lease expense incurred in the test year was $10,644 for Boston Gas, $636 for Essex Gas, and $2,412 for Colonial Gas (Exh. AG-1-37 (Supp.)). National Grid reports that three vehicle leases expire on August 1, 2009, August 18, 2010, and January 19, 2011 (Exh. DPU-10-6). National Grid failed to provide information on the duration of the remaining two leases (see Exh. DPU-10-6). No party commented on this issue.

2. Analysis and Findings

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. National Grid Electric Company, D.P.U. 09-39, at 154 (2009); Boston Gas Company, D.T.E. 03-40, at 171 (2003); Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1989). Such lease expenses, however, must be representative of the level of expenses to be incurred by the company in the future. National Grid Electric Company, D.P.U. 09-39, at 158-159 (2009); Western Massachusetts Electric Company, D.P.U. 87-260, at 75 (1988).

During the test year, Boston Gas-Essex Gas incurred $11,280 in expenses related to the leasing of vehicles, and Colonial Gas incurred $2,412 in the same expenses (Exh. AG-1-37 (Supp.)). National Grid reports that three of the leases have either expired or will expire shortly after the rates authorized herein go into effect (Exh. DPU-10-6). Thus, these expenses are not representative of the level of expenses to be incurred by the Companies in the future. Further, National Grid did not provide information on the duration of the two remaining leases, thus failing to demonstrate that these expenses will be recurring in nature.

Consequently, the Department will not permit the retention of the lease expenses in the costs of service of Boston Gas-Essex Gas or Colonial Gas. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 158-159 (2009); Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 153 (1991); Western Massachusetts Electric Company, D.P.U. 87-260, at 75 (1988). Accordingly, the Department will reduce the cost of service of Boston Gas-Essex Gas by $11,280 and will reduce the cost of service of Colonial Gas by $2,412.

W. Employee Reimbursements

1. Introduction

During the test year, the National Grid service companies allocated $3,138,900 to Boston Gas-Essex Gas and Colonial Gas for employee reimbursements to officers and directors.[283] National Grid has a policy of reimbursing employees for expenses that they incur on behalf of National Grid for valid business purposes (Exhs. AG 32-8; DPU-10-9, Att.; Tr. 14, at 1863-1864, 1867). These employee expenses reimbursed by National Grid include items such as air and ground transportation, lodging, and business meals (Exhs. AG-32-8; DPU-10-9, Att.; DPU-10-4).

283 National Grid did not provide a breakdown of the total test year costs between Boston Gas-Essex Gas and Colonial Gas (see Exhs. AG-1-38(A), AG-1-38(B)).

In its initial filing, National Grid excluded from its test year cost of service $49,164 relating to entertainment expenses (RR-AG-74).[284] As a result of questions raised during the proceeding, National Grid removed an additional $105,174 and $7,156 from the test year costs of service for Boston Gas-Essex Gas and Colonial Gas, respectively, for employee reimbursements related to expatriate expenses, including housing rentals, travel for family and pets, and prescription costs (Exhs. NG-MDL-2-Boston Gas (Rev. 3) (Changes Identified Post Filing); NG-MDL-2-Colonial Gas (Rev. 3) (Changes Identified Post Filing; RR-AG-71).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Department should disallow 50 percent, or $171,500, of the reimbursable employee expenses of officers and directors that the Companies seek to recover in its cost of service (Attorney General Brief at 116-118, 120, citing, e.g., Exhs. AG-32-20; AG-32-22; AG-32-46).[285] The Attorney General maintains that in order to recover costs incurred from an affiliate, a company must show that the costs: (1) are specifically beneficial to the individual company seeking rate relief; (2) reflect a reasonable and competitive price; and (3) are allocated by a formula that is cost-effective and nondiscriminatory (Attorney General Brief at 118, 120, citing Boston Edison Company,

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284 In excluding entertainment costs, National Grid stated that while it considered these types of costs to be reasonable costs incurred in the normal course of business, it omitted this category of expense in order to conserve internal review resources and limit the cost of litigating smaller, controversial items (RR-AG-74).

285 It is not immediately apparent how the Attorney General derived the $343,000 ($171,500 x 2) in employee reimbursements from the exhibits cited in her brief.

D.T.E. 99-19, at 94 (1999); Oxford Water Company, D.P.U. 1699, at 10-13 (1984)). The Attorney General asserts that National Grid has taken advantage of the Department's precedent on cost recovery (which allows certain service company employee expenses to be included in a local distribution company's cost of service) and engaged in a systematic practice of charging Massachusetts ratepayers for employee expenses that in no way benefit them (Attorney General Brief at 116).

The Attorney General asserts that National Grid acknowledged that in order to charge costs to the Companies, the activity must be associated with the Companies' provision of service to Massachusetts ratepayers (Attorney General Brief at 117, citing Tr. 14, at 148-149). The Attorney General contends that despite this acknowledgement, the Companies included numerous employee expenses that are not properly recoverable from Massachusetts ratepayers (Attorney General Brief at 118, citing Exhs. AG-32-20, at 1, 12; AG-32-22, at 1, 12; AG-32-44, at 6, 17; AG-32-45, at 9; AG-32-46, at 10). For example, the Attorney General asserts that expenses related to meetings with the NewYork Public Service Commission, attendance at rate hearings in New Hampshire, and expenses related to attendance at the Presidential Inauguration should not be recoverable from Massachusetts ratepayers (Attorney General Brief at 118, citing Exhs. AG-32-20, at 1, 12).

The Attorney General argues that National Grid attempted to justify charging the Companies for the employee expenses by using a 'global theory" – i.e., the performance of non-specific regulatory activity in all of National Grid plc's jurisdictions within the United States provides customers with the benefit of the Companies' keeping abreast of general regulatory issues (Attorney General Brief at 118, citing Tr. 14, at 1952-1953; RR-AG-76). The Attorney General asserts that National Grid's explanation of benefit to ratepayers is so vague that it could apply to all activities undertaken by any National Grid plc employee, regardless of service territory or utility type (Attorney General Brief at 119). The Attorney General also claims that the expense descriptions contained in the employee expense reports are not actually descriptive, and given the limited time of a rate case proceeding, further detailed analysis was not possible (Attorney General Brief at 118, 120).

In response to National Grid's arguments that the service company charges have been approved by the Securities and Exchange Commission ("SEC") and that the Federal Energy Regulatory Commission ("FERC") has jurisdiction over service companies, the Attorney General argues that the Department is not bound by any accounting treatment afforded service company charges that are overseen by the SEC or FERC (Attorney General Reply Brief at 57-58, citing Boston Edison Company, D.T.E. 97-95, at 76-77 (2001); 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 Attorney General also asserts that while accounting requirements prescribed by FERC or the Financial Accounting Standards Board ("FASB") may be instructive, they do not compel the Department to adopt a particular method for ratemaking purposes (Attorney General Reply Brief at 58).

The Attorney General also asserts that the Companies should be required to identify in a compliance filing all charitable contributions included in employee expense reports (Attorney General Brief at 121). Further the Attorney General states that National Grid should be required to identify all expenses related to contact with elected local, state, and federal employees to ensure compliance with the Department's lobbying precedent (Attorney General Brief at 121).

Moreover, the Attorney General asserts that National Grid has misallocated service company costs to the Companies that cause a distortion of cost of service (Attorney General Reply Brief at 58). Specifically, the Attorney General contends that National Grid has charged the Companies excessive overheads on service company allocations that may exceed $104.3 million and collectively indicate that the Companies have not demonstrated a need for any increase in base rates at this time (Attorney General Reply Brief at 58-59, citing Exh. AG-1-2(5) (2009 FERC Form 60, for National Grid Corporate Service Company at 307).

Because of her concerns that service company costs may not be appropriately allocated, the Attorney General asks that the Department, pursuant to its general supervisory authority over affiliated companies, require an independent audit of the NGSC and the allocations and assignments of employee and other costs to Boston Gas, Essex Gas, and Colonial Gas (Attorney General Brief at 122, citing D.P.U./D.T.E. 97-96, at 5 (1998); G.L. c. 164, § 76A; G.L. c. 25, § 5E). The Attorney General asserts that by proposing to obtain its own independent auditor, National Grid is attempting to control the audit process so that the Department and interested stakeholders have no part in shaping the scope of the investigation, choosing the auditor, receiving reports as to the audit's progress, and weighing in on draft reports prior to finalization (Attorney General Reply Brief at 59-60). The Attorney General argues that National Grid's proposal would result in a truncated review that does not provide the full measure of protection that ratepayers are due and, thus, should be rejected (Attorney General Reply Brief at 60).

b. National Grid

National Grid asserts that in claiming that certain employee reimbursements are not appropriate for recovery in rates, the Attorney General is attempting to leverage a minor ratemaking issue into the basis for sweeping disallowances of service company allocations and to commence an audit into National Grid's financial operations (National Grid Brief at I.9; National Grid Reply Brief at 100, citing Attorney General Brief at 131; Attorney General Reply Brief at 57-60). National Grid maintains that certain employee reimbursements may have only an indirect relation to the conduct of gas distribution operations but that "these costs are legitimately incurred by employees in travelling, attending meetings, eating, gaining admission, building relationships, and relocating families" in furtherance of the gas distribution business (National Grid Brief at I.10). National Grid further maintains that the Attorney General's view that more than $100 million in service company charges may be improper is based on the false premise that there should be an apparent correlation in the cost of service between the amount of service company costs charged to the Massachusetts gas companies and the costs that are directly incurred by those companies (National Grid Reply Brief at 100, citing Attorney General Brief at 131; Attorney General Reply Brief at 57-60).

National Grid also contends that, in arguing that the Department should disallow 50 percent of the employee reimbursements, the Attorney General has chosen an arbitrary amount that has no evidentiary basis (National Grid Brief at IX.25-26, citing Attorney General

Brief at 117-118). National Grid states that it submitted a voluntary adjustment to its cost of service to remove $805,103, representing 100 percent of expatriate payroll and benefit and employee costs charged to the Companies in the test year as well as 1,005 employee expense items determined to have been incurred by officers and directors of Boston Gas, Essex Gas, Colonial Gas, Niagara Mohawk Power Corporation, and the NGSC service companies (National Grid Brief at IX.25).[286] National Grid asserts that this adjustment addresses the Attorney General's argument that expenses should be disallowed because they relate neither to Massachusetts customers nor to the conduct of business in the Companies' Massachusetts service territories and, therefore, that no further adjustment is warranted (National Grid Brief at IX.25). With respect to charitable contributions and lobbying expenses, National Grid asserts that it has already confirmed that reimbursements to employees for such expenses are not included in the test year employee reimbursement expense (National Grid Brief at IX.26 n.4).

National Grid argues that the Department should not require the independent audit that the Attorney General recommends the Department undertake for two reasons (National Grid Brief at IX.26). First, National Grid argues that FERC is in the final stages of completing an audit of the service company allocation process used by the National Grid service companies and that National Grid will provide it to the Department upon its completion (National Grid

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286 In addition to the $112,330 removed by National Grid for employee reimbursements, the Companies removed $617,769 and $75,005 for Boston Gas-Essex Gas and Colonial Gas, respectively, for expatriate employees' payroll related costs (Exhs. NG-MDL-2-Boston Gas (Rev. 3) (Changes Identified Post Filing); NG-MDL-2-Colonial Gas (Rev. 30 (Changes Identified Post Filing)).

Brief at IX.26). Second, National Grid maintains that it intends to retain an outside, independent firm to conduct a comprehensive review of its policies and practices to distinguish the expatriate costs that are appropriate for inclusion in cost of service and to ensure the appropriate allocation of such costs (National Grid Brief at IX.26).

3. Analysis and Findings

The Department has stated that in order for a company to include expenses such as employee reimbursements in its test year cost of service, the company bears the burden of demonstrating that the costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. Boston Gas Company, D.T.E. 03-40, at 140-141 (2003); Oxford Water Company, D.P.U. 1699, at 13 (1984).[287] As an initial matter, we note that pursuant to National Grid's policy in effect during the test year, foreign employees undertaking a long-term assignment in the United States were reimbursed for certain costs related to the international assignment (RR-AG-72(B)). Examples of the reimbursed costs for expatriates included (1) health care costs that exceed costs covered by the employees' home country's health insurance; (2) moving costs for family, domestic pets, and most household goods and personal effects; (3) house rentals, utilities, and telephone charges; (4) an annual vacation for the employee and family members to the home country; and (5) private school for dependent children in certain circumstances (RR-AG-72(B) at 8, 9 10, 14, 16, 18).

National Grid allocated a portion of these expatriate reimbursed costs to Massachusetts ratepayers (see, e.g., Exhs. AG-32-45; AG-32-48; AG-32-49). The Companies maintain that

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287 The Department has stated that this standard applies whether the expenses were incurred at the parent level or at the service company level. D.T.E. 03-40, at 140-141.

these costs may be viewed out of context as having only an indirect relationship to the conduct of gas distribution company operations (National Grid Brief at I.10). The Companies assert, however, that these costs are legitimately incurred by employees in furtherance of the gas distribution business (National Grid Brief at I.10). Nonetheless, during the course of the proceeding, National Grid removed the reimbursements for expatriate expenses from the test year costs of service, resulting in a decrease in employee reimbursements of $105,174 and $7,156 for Boston Gas-Essex Gas and Colonial Gas, respectively (Exhs. NG MDL 2 Boston Gas (Rev. 3) (Changes Identified Post Filing); NG MDL 2 Colonial Gas (Rev. 3) (Changes Identified Post Filing); RR-AG-71).[288] Because National Grid removed these costs from its test year cost of service, the Department is not required to analyze the appropriateness of the inclusion of such costs in the test year. We take this opportunity, however, to remind the Companies that any attempt to allocate similar costs to Massachusetts ratepayers must be accompanied by an adequate showing that the costs directly benefit Massachusetts ratepayers and are reasonable and were prudently incurred. As outlined below, National Grid has not demonstrated that certain of the remaining employee reimbursements to officers and directors

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[288] During the proceeding, the Attorney General inquired about particular expatriate costs, including those related to shipping an executive's wine collection from Great Britain to the United States and an executive's private school tuition for his children (Tr. 14, at 1861). While the shipping and schooling costs were identified during the discovery process, National Grid did not propose to recover them from Massachusetts ratepayers (Exh. AG-32-45). Had National Grid sought to recover such costs in this proceeding, it would have been required to demonstrate a direct benefit to Massachusetts ratepayers and that such costs were reasonable and prudently incurred. On their face, these costs would not have passed this standard.

directly benefit Massachusetts ratepayers. Nor has National Grid demonstrated that certain of these remaining employee reimbursements are reasonable and were prudently incurred.

First, as noted by the Attorney General, many of the employee reimbursements do not contain sufficient explanation to ensure that the costs were appropriately allocated to the Companies. For example, the exhibits at issue include reference to miscellaneous costs with no further explanation (see, e.g., Exhs. AG-32-20; AG-32-44). In addition, some of the exhibits simply include reference to the reimbursement for expenses incurred either (1) during a specific time period or (2) for "meetings" with no further delineation or explanation (see, e.g., Exhs. AG-32-20; AG-32-21; AG-32-22). Further, Exhibit AG-32-42 outlines hotel costs; however, the bulk of the costs are simply labeled with the name of the hotel or hotel reservations company and no further explanation is provided as to the purpose of the hotel stay. During the limited statutory time period permitted for review of a rate case filing, there is scant time for the Department and interested parties to investigate the appropriateness of each individual line item. Nonetheless, National Grid bears the burden of demonstrating that only costs that benefit Massachusetts ratepayers are allocated to the Companies. It has failed to do so in the foregoing instances. D.T.E. 03-40, at 140-141; Oxford Water Company, D.P.U. 1699, at 13 (1984).

Second, where more detail is provided regarding the expense, we determine that in several circumstances National Grid has allocated costs to Boston Gas-Essex Gas and Colonial Gas for activities that provide no benefit to Massachusetts ratepayers. For example, National Grid has allocated costs to the Companies that involve public hearings, meetings, technical sessions, and rate cases before the New Hampshire Public Service Commission and the New York Public Utilities Commission (see, e.g., Exhs. AG-32-20; AG-32-21). National Grid also allocated to the Companies travel costs relating to attendance at the Presidential Inauguration. This is not the kind of expenditure that should be borne by Massachusetts ratepayers (see, e.g., AG-32-20; AG-32-21).

The Attorney General disputes National Grid's assertion that engaging in regulatory activity in all of its jurisdictions provides Massachusetts customers with a benefit by keeping the Companies abreast of general regulatory issues (Attorney General Brief at 119, citing RR-AG-76).[289] We agree with the Attorney General. While there may be a benefit to Massachusetts ratepayers where the officers and directors participate in general informational conferences, there is no benefit to Massachusetts ratepayers where the officers and directors participate in a rate case or proceeding that occurs in a service territory outside of Massachusetts. If we were to accept National Grid's argument, it could lead to the inclusion of costs in Massachusetts gas rates from regulatory proceedings throughout National Grid's international territory.

Thus, for the reasons discussed above and in addition to the other amounts for which the Companies will not be allowed recovery as discussed, the Department will disallow the

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289 As noted above, the Attorney General also argues that National Grid appears to have charged the Companies excessive overheads on service company allocations (Attorney General Reply Brief at 58-59, citing Exh. AG-1-2(5) (2009 FERC Form 60, for National Grid Corporate Service Company at 307). The Attorney General, however, has taken a simplistic approach of dividing indirect costs by direct costs and asserting that the resulting calculation constitutes overhead costs. The fact that indirect costs are not a function of direct costs is sufficient to demonstrate the fallacy of the Attorney General's mathematical assertion.

following employee reimbursement expenses: (1) $920 in miscellaneous expenses, allocated as $777 to Boston Gas-Essex Gas and $143 to Colonial Gas (Exh. AG-32-20); (2) $1,741 in lodging expenses, allocated as $1,425 to Boston Gas-Essex Gas and $316 to Colonial Gas (Exh. AG-32-21); (3) $3,747 in air transportation expenses, allocated as $3,088 to Boston Gas-Essex Gas and $659 to Colonial Gas (Exh. AG-32-22); (4) $2,639 in hotel expenses, allocated as $2,082 to Boston Gas-Essex Gas and $557 to Colonial Gas (Exh. AG-32-42); (5) $1,802 in airfare expenses, allocated as $1,547 to Boston Gas-Essex Gas and $255 to Colonial Gas (Exh. AG-32-43); (6) $270 in other expenses, allocated as $231 to Boston Gas-Essex Gas and $38 to Colonial Gas (Exh. AG-32-44); (7) $412 in business meeting expenses, allocated as $353 to Boston Gas-Essex Gas and $59 to Colonial Gas (Exh. AG-32-46); and (8) $334 in transportation expenses, allocated as $286 to Boston Gas-Essex Gas and $48 to Colonial Gas (Exh. AG-32-47).[290] Going forward National Grid is directed to improve its record keeping for employee reimbursements to include sufficient detail about the nature and the purpose of the expense in question, including explanation as to how each specific expense is directly related to utility operations in Massachusetts. See D.T.E. 03-40, at 140-141; D.P.U. 1699, at 13.

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290 During the proceeding, National Grid removed $105,174 and $7,156 for Boston Gas Essex Gas and Colonial Gas, respectively, for employee reimbursements (Exhs. NG-MDL-2-Boston Gas (Rev. 3) (Changes Identified Post Filing); NG-MDL-2-Colonial Gas (Rev. 3) (Changes Identified Post Filing); RR AG 71). As noted in n. 178, above, the Department removed these employee reimbursements along with expatriate payroll-related costs from the test year costs of service as a single line item labeled "Expatriate, Officer, Director Expenses" on Schedules 2, below (i.e., the Department removed $722,943 for Boston Gas-Essex Gas and $82,161 for Colonial Gas).

The Attorney General also asserts that the Companies should be required to submit as a compliance filing to demonstrate that no charitable contributions and lobbying expenses are included as employee reimbursements (Attorney General Brief at 121). National Grid asserts that none of these types of reimbursements is included in the test year employee reimbursement expenses (National Grid's Brief at IX.26 n.4). National Grid does not, however, cite to any evidence to support this claim. Nonetheless, we are unable to find any evidence that charitable contributions and lobbying expenses are included in employee reimbursements and the Attorney General had an opportunity to question the Companies regarding the inclusion of such costs during the proceeding. Further, a compliance filing is not the appropriate venue to establish a revenue requirement. Instead, the revenue requirement is established by the final Order issued by the Department and the compliance filing is then used to determine that National Grid has appropriately used the established revenue requirement in its rate design. Accordingly, we will not require the Companies to submit further documentation regarding charitable contributions or lobbying expenses.

Finally, the Attorney General asks that the Department undertake an audit to review the allocations and assignments of employee and other costs to the Companies from the service companies pursuant to our general supervisory authority (Attorney General Brief at 122, citing G.L. c. 164, § 76A; G.L. c. 25, § 5E). The Attorney General asks that such a financial audit be used to uncover specific instances of inappropriate allocations and also to identify flaws in the methods the Companies use to determine whether it is appropriate to assign or allocate certain expenses for recovery from Massachusetts ratepayers (Attorney General Brief at

122-123). The Attorney General also asserts that the audit should include the review and validation of the Companies' accounting records and reports, compliance with generally accepted accounting principles and regulatory accounting standards and requirements, and compliance with Department Orders, regulations, and precedent (Attorney General Brief at 123). National Grid asserts that such an independent audit is unnecessary because it intends to conduct its own review of service company allocations and FERC is also in the final stages of an audit of service company allocation processes (National Grid Brief at IX.26).

In reviewing the allocations from the service companies, we are concerned that National Grid may be allocating expenses to the Companies that should be borne by other National Grid companies or by shareholders. For example, as outlined above, there is insufficient detail in the documentation to determine that the expenses should be allocated to the Companies. In addition, as noted above, National Grid is allocating costs to the Companies for regulatory proceedings that take place outside of Massachusetts. Therefore, we will open an investigation to address the allocation and assignment of costs to the Companies by the National Grid service companies. This matter will be docketed as D.P.U. 10-155. The scope of and procedures for the audit will be determined by the Department after comment from interested stakeholders, and, in establishing the scope of the audit, we will consider the specific recommendations made by the Attorney General in this proceeding.[291] Pursuant to G.L. c. 25, § 5E, the costs of the audit shall be borne by National Grid shareholders.

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[291] The Department puts the Companies on notice that such audit must be completed, and any issues identified by the audit relating to service company allocations must be resolved to the Department's satisfaction, before any allocations from the service

X. Farm Discount Rate

1. Introduction

In Farm Discounts, D.T.E. 98-47, at 5-6 (1998), the Department addressed, among other things, the recovery of expenses by local gas distribution companies related to the implementation of the legislatively-mandated farm discount.[292] The Department stated that local gas distribution companies "may defer costs associated with the implementation of the farm discount for consideration in a subsequent general rate case." D.T.E. 98-47, at 6.

In the current proceeding, National Grid does not propose to collect any deferred costs related to the implementation of the farm discount (Exh. DPU-18-6, Tr. 10, at 1306).[293] Instead, National Grid proposes to create a new fully reconciling mechanism to recover costs related to the farm discount on a going-forward basis through its local distribution adjustment

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companies will be permitted in the test year cost of service in any future rate case filing the Companies may make.

[292] On November 25, 1997, Chapter 164 of the Acts of 1997, entitled "An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein" ("Act") was signed by the Governor. Section 315 of the Act requires Massachusetts electric and gas distribution companies and municipal lighting plants to provide customers who meet certain eligibility requirements for being engaged in the business of agriculture or farming an additional ten percent reduction ("Farm Discount") in the rates to which such customers would otherwise be subject. St. 1997, c. 164, § 315.

[293] Boston Gas did not seek recovery of any deferred costs associated with the implementation of the farm discount in its last rate case, D.T.E 03-40. For both Essex Gas and Colonial Gas, this is the first rate case since the farm discount was established in 1998 (Exh. DPU-18-6).

factor ("LDAF") (Exhs. NG-AEL-1, at 23, 26-27; NG-AEL-4, at 37, 56-57).[294] The Companies propose separate farm discount factors for Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-AEL-4, at 56; DPU-18-6). No parties commented on National Grid's farm discount cost recovery proposal.

2. Analysis and Findings

As noted above, in D.T.E. 98-47, at 6, the Department stated that gas distribution companies may defer costs associated with the implementation of the farm discount for consideration in a subsequent rate case. As a result, several local gas distribution companies received approval in a general rate case to recover deferred amounts of revenue discounts made available to qualified farm customers. See e.g., D.P.U. 09-30, at 263-264; D.T.E. 05-27, at 190-191; D.T.E. 02-24/25, at 203-205. In each case, the deferred farm discount costs were normalized to lower the local distribution company's cost of service in the test year. D.P.U. 09-30, at 263-264; D.T.E. 05-27, at 190-191; D.T.E. 02-24/25, at 204-205, D.T.E. 01-56 at 35-36.

In this current rate case, National Grid does not seek recovery of any deferred costs related to the farm discount as authorized by D.T.E. 98-47. Instead, National Grid seeks to create a new fully reconciling mechanism to collect future farm discount costs (Exhs. NG-AEL-1, at 23, 26-27; NG-AEL-4, at 37, 56-57; Tr. 10, at 1306). National Grid states

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294 The Companies propose to recover the actual cost of the farm discount for the period November 2010 through April 2011 in the November 2011 to October 2012 LDAF (Exh. DPU-18-6). National Grid proposes to include the actual farm discount for the period of May 2011 through April 2012 in the subsequent LDAF filing (Exhs. NG-AEL-4 at 37; DPU-18-6).

that its proposed cost recovery method is similar to the manner in which the Department permits companies to recover the low income discount through a reconciling factor in the LDAF (Exh. DPU-18-6).

The Department does not create new fully reconciling cost mechanisms lightly. Specific criteria the Department considers when determining whether to create a new fully reconciling cost recovery mechanism include whether the costs at issue are: (1) volatile; (2) large in magnitude; (3) neutral to fluctuation in sales; and (4) beyond the control of the company. See e.g., Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005); NSTAR Electric Company/NSTAR Gas Company, D.T.E. 03-47-A, at 25-28, 36-37 (2003); Eastern-Essex Acquisition, D.T.E. 98-27, at 6, 28 (1998). With respect to the continuation of fully reconciling cost recovery mechanisms after decoupling, the Department has put all companies on notice that we will consider which, if any, of the currently reconciled costs should continue to be fully reconciled through a separate mechanism or recovered instead through base rates. D.P.U. 07-50-A at 50. The Department stated that such consideration would take place on a case-by-case basis, in which each distribution company must demonstrate that continued recovery in a separate mechanism is warranted. Likewise, companies seeking to create new fully reconciling cost recovery mechanisms must demonstrate that recovery in a separate mechanism is warranted.

As the farm discount is legislatively-mandated, it is beyond the control of the Companies. See Electric Restructuring, St. 1997, c. 164, § 315. However, farm discount costs are neither large in magnitude nor volatile. A limited number of National Grid customers are eligible for the farm discount and the number of eligible customers is not expected to change significantly over time (Tr. 10, at 1307). The total dollar amount of the farm discount in 2009 for Boston Gas-Essex Gas was $73,251, while the total discount for Colonial Gas was $158,422 (Exh. DPU-18-5, Att. (A); Tr. 10, at 1306). The Department notes that this amount represents less than 0.016 percent of National Grid's total cost of service (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 6; NG-MDL-2-Colonial Gas (Rev. 3) at 6).[295] The amount of the farm discount does not vary significantly from year to year and the Company has not significantly increased or decreased its customer base since 2004 (Exh. DPU-18-5, Att. A; DPU-18-5, Att. B).

In D.T.E. 98-47, at 6, the Department stated that deferred costs related to the implementation of the farm discount would be considered in a subsequent rate case. The Department did not suggest that fully-reconciling cost recovery mechanism was appropriate for farm discount costs and, in fact, we declined to accept The Berkshire Gas Company's proposal to recover the cost of the farm discount through the local distribution adjustment clause. D.T.E. 98-47, at 3, 6. No other gas distribution company recovers farm discount costs through a fully reconciling mechanism. See e.g., D.P.U. 09-30, at 263-264; D.T.E. 05-27, at 190-191; D.T.E. 02-24/25, at 203-205. While the Department does permit recovery of costs related to the low-income discount through a fully reconciling mechanism, this mechanism was established in a generic proceeding specifically designed to increase

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295 The Department divided the total test year farm discount of $231,673 by National Grid's combined cost of service of $1,155,260,966 for Boston Gas-Essex Gas and $301,802,543 for Colonial Gas to arrive at this figure.

participation in the low-income discount rate. Low-Income Discount, D.T.E. 01-106-A (2003). The same policy considerations do not exist here.

Accordingly, based on our review of the factors discussed above, we find that National Grid has failed to demonstrate that recovery of the farm discount costs in a separate fully reconciling mechanism is warranted. Consistent with our directives in D.T.E. 98-47 and the farm discount cost recovery proposals approved for other local gas distribution companies, National Grid may request that the Department consider deferred costs associated with the implementation of the farm discount in its next rate case. See D.P.U. 09-30, at 263-264; D.T.E. 05-27, at 190-191; D.T.E. 02-24/25, at 203-205. National Grid shall revise its proposed LDAC tariffs accordingly to remove the farm discount reconciling mechanism and all references thereto.

XI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid proposes a 9.66 percent weighted average cost of capital ("WACC") for Boston Gas-Essex Gas and a 9.65 percent WACC for Colonial Gas, representing the rate of return to be applied on rate base to determine the Companies' total return on its investment (Exhs. NG-PRM-1, at 3; NG-PRM-1, Sch. NG-PRM-1). This rate is based on: (1) a proposed capital structure that consists of 46.36 percent long-term debt and 53.64 percent common equity for Boston Gas-Essex Gas, and 46.04 percent long-term debt and 53.96 percent common equity for Colonial Gas; (2) a proposed cost of long-term debt of 7.76 percent for Boston Gas-Essex Gas and 7.72 percent for Colonial Gas; and (3) a proposed rate of return on common equity ("return on equity" or "ROE") of 11.30 percent each for Boston Gas-Essex Gas and Colonial Gas (Exhs. NG-PRM-1, at 22, 24, 25; NG-PRM-1, Sch. NG-PRM-1). In determining its proposed ROE, the Companies applied the discounted cash flow ("DCF") model, the risk premium model, and the capital asset pricing model ("CAPM") using the market and financial data developed for a comparison group of seven gas distribution companies (Exhs. NG-PRM-1, at 25-26, 44, 50; WP NG-PRM-E; WP NG-PRM-G; WP NG-PRM-H). The Companies also applied the comparable earnings model using the market financial data for a group of 25 non-utility companies (Exhs. NG-PRM-1, at 55; NG-PRM-1, Sch. NG-PRM-13).

The components of the Companies' proposal, including the companies that comprise the comparison group, and the rate of return impact of the Companies' proposed revenue decoupling mechanism are discussed below. In addition, we discuss the recommendations of the Attorney General's cost of capital witness below. No other parties commented on the Companies' proposed capital structure and rate of return.

B. Capital Structure and Cost of Long Term Debt

1. Introduction

At the end of the test year, Boston Gas-Essex Gas' capital structure consisted of $583,000,000 in long-term debt and $674,431,797 in common equity (net of $394,547,000 in goodwill), and corresponded to a capitalization ratio of 46.36 percent long-term debt and 53.64 percent common equity (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 41; NG-PRM-1, Sch. NG-PRM-5, at 1). At the same time, Colonial Gas' capital structure consisted of

$124,000,000 in long-term debt and $145,306,000 in common equity (net of $394,547,000 in goodwill), and corresponded to a capitalization ratio of 46.04 percent long-term debt and 53.96 percent common equity (Exhs. NG-MDL-2-Colonial Gas (Rev. 3) at 40; NG-PRM-1, Sch. NG-PRM-5, at 2).

Boston Gas-Essex Gas' long-term debt consists of $183,000,000 in medium-term notes carrying interest rates ranging from 6.80 percent to 9.68 percent, as well as $400,000,000 in intercompany notes issued by KeySpan at an interest rate of 7.63 percent (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 41; Supplemental Filing, 2009 Annual Report at 33). Colonial Gas' long-term debt consists of $75,000,000 in first mortgage bonds carrying interest rates ranging from 6.90 percent to 8.80 percent, as well as $49,000,000 in intercompany debt in the form of two notes issued by KeySpan at interest rates of 7.63 percent and 7.25 percent (Exhs. NG-MDL-2-Colonial Gas (Rev. 3) at 41; Supplemental Filing, 2009 Annual Report at 33).

Boston Gas-Essex Gas' common equity balance exclude $394,547,000 in unamortized goodwill that had been recorded under Generally Accepted Accounting Principles ("GAAP") as a result of the 2000 acquisition of Eastern Enterprises by KeySpan and 2007 acquisition of KeySpan by National Grid (Exhs. NG-PRM-1, at 22; NG-PRM-1, Sch. NG- PRM-5, at 1). Similarly, Colonial Gas excluded from its common equity balance $191,001,000 in goodwill associated with these acquisitions (Exh. NG-PRM-1, Sch. NG-PRM-5, at 2). The Companies also excluded from their common equity balances the effect of accumulated other comprehensive income ("AOCI") (Exh. NG-PRM-1, at 18; NG-PRM-1, Sch. NG-PRM-2, at 3). For the test year ended December 31, 2009, National Grid calculated a 7.76 percent cost of long-term debt for Boston Gas-Essex Gas and a 7.72 percent cost of long-term debt for Colonial Gas (Exhs. NG-PRM-1, at 24; NG-PRM-1, Sch. NG-PRM-6).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that National Grid's capital structures would unfairly burden ratepayers (Attorney General Brief at 157). Further, the Attorney General argues that the Companies' proposed capital structures are not appropriate and are not in line with other companies in the gas industry (Attorney General Brief at 158). According to the Attorney General, the Companies' common equity ratios are high compared to similar gas companies (Attorney General Brief at 158).

As one remedy, the Attorney General proposes to include the Companies' short-term debt in capitalization (Exh. AG-JRW at 14-15). According to the Attorney General, gas companies commonly use short-term debt for capital purposes and thus this short-term debt must be recognized for ratemaking purposes (Attorney General Brief at 159-160, citing D.P.U. 08-27, at 126-127; North Attleboro Gas Company, D.P.U. 86-86, at 22-23 (1986); Chatham Water Company, D.P.U. 323, at 8 (1981); Attorney General Reply Brief at 47-48). By including National Grid's short-term debt in the Companies' capitalization, the Attorney General derives capital structures consisting of 10.21 percent of short-term debt, 39.92 percent long-term debt, and 49.88 percent common equity for both Boston Gas-Essex Gas and Colonial Gas (Exh. AG-JRW-5, at 1). The Attorney General argues that Boston Gas has consistently and inappropriately used short-term debt in place of long-term debt, as evidenced by the increase in short-term debt held by that company from $251.6 million to $447.8 million in years 2004-2008 (Attorney General Brief at 160, citing Exh. NG-PRM-1, Sch. NG-PRM-2, at 1). In addition, the Attorney General maintains that, based on the historic common equity ratios of the Companies, their capital structures are in transition as a result of decoupling, and this transition must be recognized for ratemaking purposes (Attorney General Brief at 161; Attorney General Reply Brief at 48).

Turning to the Companies' existing long-term debt, the Attorney General first argues that the Companies' intercompany loans are based on a "push-down" of a portion of a $700 million, ten-year medium-term note issued on November 15, 2000, which is scheduled to mature on November 15, 2010 (Attorney General Brief at 163, citing Exh. AG-20-1; Attorney General Reply Brief at 48). The Attorney General maintains that the intercompany loans are at rates in excess of current market conditions and questions National Grid's prudence in failing to refinance this debt at a more favorable rate (Attorney General Brief at 164; Attorney General Reply Brief at 50-51). Thus, the Attorney General proposes that the cost of this debt should be reduced in exercise of the Department's supervisory authority over utility affiliates, and that the Department make specific findings of fact regarding the imprudence of National Grid's failure to refinance the intercompany notes (Attorney General Brief at 161-163; Attorney General Reply Brief at 50-51).

The Attorney General proposes that, in view of current market conditions, the intercompany debt can be refinanced at an interest rate of less than 5.0 percent (Attorney

General Brief at 164, citing Exhs. AG-JWR-5, at 6; AG-JRW-Rebuttal at 6; Attorney General Reply Brief at 49).[296] The Attorney General proposes, however, what she characterizes as a "company-friendly" alternative method of calculating the appropriate interest rate to arrive at what she contends is a conservative interest rate of 5.25 percent (Attorney General Brief at 165, citing Exhs. AG-JWR-5, at 6). Application of this alternative interest rate to National Grid's intercompany debt produces a composite interest rate of 6.13 percent for Boston Gas-Essex Gas and 6.82 percent for Colonial Gas (Attorney General Brief at 165, citing Exh. AG-JRW-Rebuttal at 16).

b. National Grid

National Grid claims that its actual capital structure at test year-end is virtually identical to the capital structure approved for Bay State in D.P.U. 09-30 (National Grid Brief at VIII.2; National Grid Reply Brief at 78-79). The Companies add that their proposed capital structure ratios are also consistent with the equity-to-capital ratio of the comparison group of companies used as a basis for calculating its proposed ROE (National Grid Brief at VIII.2; National Grid Reply Brief at 79). National Grid contends that the Attorney General's proposed inclusion of short-term debt in capitalization is contrary to Department precedent because the Attorney General has failed to point to a single Massachusetts gas or electric utility where short-term debt has been included in capital structure (National Grid Brief at VIII.16-17; National Grid Reply Brief at 79). The Companies argue that the Attorney General's reliance on the practices

296 In her reply brief, the Attorney General submits that an interest rate of 4.11 percent would have been a reasonable proxy for the intercompany loans (Attorney General Reply Brief at 49-50, citing Exhs. NG-PRM-1, Schs. NG-PRM-10, at 3; NG-PRM-12, at 3).

of other state commissions is misplaced and that the Attorney General herself has conceded that a company's actual capital structure should be used for ratemaking purposes (National Grid Brief at VIII.17-18, citing Attorney General Brief at 158-160).

The Companies state that their calculations of the effective cost rate of long-term debt follow the Department's procedure that provides a return of, but not return on, debt issuance expenses (Exh. NG-PRM-1, at 24). The Companies further maintain that the Attorney General's proposed adjustment to the cost of debt is not known and measurable (National Grid Brief at VIII.18). The Companies argue that there is no record evidence establishing the method by which the intercompany debt can be refinanced or even if such debt will be refinanced (National Grid Reply Brief at 80, citing Tr. 19, at 2737-2738). National Grid contends that its other similar debt was not refinanced and, instead, was paid off with cash (National Grid Reply Brief at 80, citing RR-AG-50, Att. at 56-57). The Companies argue that if the debt was replaced with equity, the resulting costs would be higher and there is no valid basis for adopting an alternative cost for this debt (National Grid Reply Brief at 80, citing Exh. NG-PRM-Rebuttal-1, at 5).

Moreover, the Companies contend that the Attorney General's recommended cost of debt of 5.25 percent is arbitrary and unsupported by the evidence, in light of the fact that the current yield on 30-year debt is 5.69 percent for companies comparable to National Grid (National Grid Brief at VIII.19; National Grid Reply Brief at 80). The Companies maintain that, given the fluctuation in the long-term debt market and the "virtual financial panic" in the fall of 2008, it is unreasonable to claim that National Grid was somehow imprudent in failing to refinance its intercompany debt (National Grid Reply Brief at 81).

3. Analysis and Findings

a. Introduction

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 08-35, at 184; D.T.E. 05-27, at 269; 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 profits for the company to be included in its revenue requirements. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department will normally accept a utility's test year-end capital structure, allowing for known and measurable changes, unless the capital structure deviates substantially from sound utility practice. D.T.E. 03-40, at 319; High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982). In reviewing and applying utility company capital structures, the Department seeks to protect ratepayers from the effect of excessive rates of return. D.T.E. 03-40, at 319; Assabet Water Company, D.P.U. 1415, at 11 (1983); see Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 430 n.14 (1971).

b. Intercompany Debt

The $400 million in intercompany notes for Boston Gas-Essex Gas, as well as the $49 million in intercompany notes for Colonial Gas, represented a "push-down" of $700 million in acquisition debt that KeySpan incurred when it purchased Eastern Enterprises (Exhs. AG 13-9; AG 13-10; AG 13-11).[297] When KeySpan acquired Eastern Enterprises, it paid approximately $1.127 billion over book value for Eastern Enterprises' assets, thus creating a goodwill balance of approximately $1.127 billion.[298] D.T.E. 03-40, at 314. Pursuant to GAAP, KeySpan allocated these goodwill balances among its Eastern Enterprises acquisitions, including the Companies. D.T.E. 03-40, at 314.[299] At the end of the test year, the unamortized goodwill balance included on the books of Boston Gas-Essex Gas was $394,547,102 (Exh. NG-MDL-2-Boston Gas (Rev. 3) at 44). At the end of the test year, the

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297 Because Eastern Enterprises remained the Companies' parent company at the time the notes were issued, Eastern Enterprises remained the noteholder of record (Exhs. AG 13-9; AG 13-10; AG 13-11).

298 An acquisition premium, or goodwill, is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions, D.P.U. 93-167-A at 9 (1994).

299 In D.P.U. 93-167-A at 18-19, the Department amended its policy of per se exclusion in favor of case-by-case consideration of acquisition premiums as a factor in the cost-benefit analysis required as part of a merger and acquisition petition. Consequently, the Department will allow recovery of acquisition premiums as a component of the general reckoning of cost and benefit conducted under the standards of G.L. c. 164, § 96, which requires a showing that the costs or disadvantages of the transaction are accompanied by benefits that warrant their allowance. D.P.U. 93-167-A at 7. Nevertheless, rate base exclusion of acquisition premiums continues to be the norm. Southern Union Company, D.T.E. 03-64, at 10 (2003); D.T.E. 02-27, at 12.

unamortized goodwill balance included on the books of Colonial Gas was $199,000,465 (Exh. NG-MDL-2-Colonial Gas (Rev. 3) at 43). National Grid has removed this unamortized goodwill from plant in service (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 44; NG-MDL-2-Colonial Gas (Rev. 3) at 43).

The Department's ratemaking process relies on a return-on-rate-base concept in which a WACC is determined and applied to rate base in order to derive an appropriate revenue requirement. See D.P.U. 95-92, at 31; Kings Grant Water Company, D.P.U. 87-228, at 22 (1988); Nantucket Electric Company, D.P.U. 1530, at 13 (1983); New England Telephone and Telegraph Company, D.P.U. 7750 (1949) (83 P.U.R. NS 238, 282). Because the Department has consistently applied original-cost rate base principles and exercised stringent oversight over utility securities issuances, a utility's rate base frequently coincided with its total capitalization during the early years of the return-on-rate-base method. D.P.U. 7750 (83 P.U.R. NS 238, 272); Plymouth County Electric Company, D.P.U. 6369 (1941) (39 P.U.R. NS 20). In the later years, however, evolving regulatory standards for non-plant components of rate base (e.g., cash working capital, deferred income taxes), as well as the increased role of retained earnings in capitalization, have resulted in situations where total capitalization and total rate base materially differ in amount. See, e.g., Massachusetts Electric Company, D.P.U. 95-40-C at 18-19 (1995).

This disparity between capitalization and rate base, in and of itself, does not constitute a defect in the ratemaking process because it is the amount of rate base, not capitalization, that determines the level of capital costs that are recoverable through rates. D.T.E. 03-40, at 322;

D.P.U. 1247-A at 7. In this instance, however, the disparity between capitalization and rate base is quite significant, with a $982.9 million rate base versus capitalization of $1,257.4 million for Boston Gas-Essex Gas, and a $243.8 million rate base versus capitalization of $269.3 million for Colonial Gas (Exhs. NG-MDL-2-Boston Gas (Rev. 3) at 41, 43; NG-MDL-2-Colonial Gas (Rev. 3) at 40, 42). Although the magnitude of the difference is smaller for Colonial Gas than for Boston Gas-Essex Gas, the overall difference is large enough that we cannot conclude that the aggregate of $449,000,000 of intercompany notes supports, or is in any way associated with, items included in National Grid's proposed rate base. D.T.E. 03-40, at 322; cf. Boston Gas Company, D.P.U. 19470, at 80-81 (1978) (goodwill-related capitalization represented approximately 2.70 percent of total capitalization which equaled 94 percent of rate base). For these reasons, and in recognition of the underlying reason for the creation of the intercompany debt (i.e., a pushdown of acquisition premiums), we will remove the capitalization associated with the KeySpan merger for the purposes of determining National Grid's capital structure. Accordingly, Boston Gas-Essex Gas' proposed long-term debt will be reduced by $400,000,000, and Colonial Gas' proposed long-term debt will be reduced by $49,000,000.

c. Imputed Capital Structure

With the removal of the Companies' intercompany notes from their capital structures, Boston Gas-Essex Gas' capital structure consists of 21.34 percent long-term debt and 78.66 percent common equity, and Colonial Gas's capital structure consists of 34.04 percent long-term debt and 65.96 percent common equity. The Department uses a policy in reviewing and applying utility company capital structures that, inter alia, seeks to protect ratepayers from the effects of excessive rates of return. D.T.E. 03-40, at 324; D.P.U. 95-92, at 33. The Department has used a hypothetical capitalization for ratemaking purposes when the actual capitalization is found to deviate substantially from sound utility practice. D.T.E. 03-40, at 324; D.T.E. 01-50, at 25; D.P.U. 1135, at 4. When the Department has imputed a utility's capital structure, we have typically relied for ratemaking purposes on a capital structure consisting of 50 percent debt and 50 percent equity. D.T.E. 03-40, at 324; D.T.E. 01-50, at 25; D.P.U. 1360, at 26-27.

In the instant case, we find that the Companies' actual test year-end capital structure, adjusted for the removal of goodwill, is overly reliant on equity and, therefore, deviates substantially from sound utility practice. D.T.E. 03-40, at 325; D.T.E. 01-50, at 25. Imputation of a hypothetical capital structure will bring the Companies' common equity balances more into alignment with sound utility practice. Therefore, the Department will impute a hypothetical capital structure to derive the WACC for both Boston Gas-Essex Gas and Colonial Gas.

The Attorney General has proposed that the Department include National Grid's short-term debt in the Companies' capital structures (Exh. AG-JRW-1). In view of the Department's decision to impute a hypothetical capital structure, we find it unnecessary to include the Companies' short-term debt in capitalization. Accordingly, the Department will impute a hypothetical capital structure consisting of 50 percent long-term debt and 50 percent common equity to derive the WACC for both Boston Gas-Essex Gas and Colonial Gas.

d. Cost of Debt

When imputing a capital structure, it is also necessary to impute a cost of debt for the company. D.T.E. 03-40, at 328; D.P.U. 95-92, at 33. An imputed cost of debt is based on a number of considerations, including recent financings by the petitioner or other utilities, the petitioner's access to the capital markets, and current interest rates. D.T.E. 03-40, at 328; D.T.E. 01-50, at 24; D.T.E. 01-42, at 19; D.P.U. 95-92, at 33-34; South Egremont Water Company, D.P.U. 95-119/122, at 24 (1996).

National Grid's acquisition-related debt carries interest rates ranging between 7.25 percent and 7.63 percent (Exhs. NG-PRM-1, Schs. NG-PRM-1, NG-PRM-6). Use of National Grid's embedded cost of debt would fail to recognize that the Companies' embedded debt was issued at various times between 1989 and 1995 for Boston Gas and between 1992 and 1998 for Colonial Gas (Exhs. AG 1-2(8), Att. at 1632, 1756).[300] In contrast, the debt being imputed here should bear interest rates that are related to current market conditions.

The Attorney General's cost of capital witness opined that an appropriate long-term debt cost rate on the intercompany loans is 5.25 percent (Exh. AG-JRW at 16).[301] The interest rate on National Grid's current intercompany loans is based on the then-prevailing ten-year

300 Essex Gas has no long-term debt (Exh. AG 1-2(8), Att. at 1694-1695).

301 The Attorney General's witness states that, over the second quarter of 2010, the average of ten-year yields is 4.89 percent, the average of the ten-year and 30-year yields is 5.29 percent, and the average of the 30-year yields is 5.69 percent. Given these figures, and presuming a financing plan that includes both ten-year and 30-year maturity issues, the witness opined that an appropriate long-term debt cost rate on the intercompany loans is 5.25 percent (Exh. AG-JRW at 16).

U.S. Treasury yields at the time of the issuance, plus a credit spread of 175 basis points (Exhs. Rebuttal-JRW-1, at 3-4; AG-20-1). Current ten-year Treasury yields are 3.0 percent and current credit spreads remain around 175 basis points (Exh. Rebuttal-JRW-1 at 4). During the second quarter of 2010, the average yield on A-rated ten-year utility bonds was 4.84 percent, while the average yield on 30-year A-rated utility bonds was 5.63 percent (Exh. JRW-5). Based on this information and our review of the evidence, including National Grid's access to the capital markets, as well as other information on recent financings by other companies and current interest rates, the Department finds that an interest rate of 5.25 percent is a reasonable proxy for National Grid's cost of debt if the Companies were to acquire it under current market conditions. This 5.25 percent debt, when added to National Grid's other long-term debt instruments, results in an overall cost of debt of 6.07 percent for Boston Gas-Essex Gas and 6.57 percent for Colonial Gas.

C. Comparison Group

1. Description

National Grid performed its cost-of-equity analysis using average market data of the companies included in its chosen comparison group (Exhs. NG-PRM-1, at 6; NG-PRM-1, Sch. NG-PRM-3, at 2). National Grid states that it included in its comparison group all gas companies included in the Value Line Investment Survey ("Value Line") that, in its judgment, have decoupling mechanisms and other features comparable to those of the Companies (Exhs. NG-PRM-1, at 5-6; NG-PRM-1, Sch. NG-PRM-3, at 2). National Grid states that, while there are a total of twelve gas companies included in Value Line, it eliminated five companies from that list that it did not believe were comparable to the Companies (Exh. NG-PRM-1, at 5-6). Specifically, National Grid removed: (1) NiSource because of its electric and natural gas pipeline and storage operations; (2) Southwest Gas because of its service location in an arid region of the United States; (3) UGI Corporation because of its highly diversified operations; and (4) Laclede Group and NICOR because none of these companies has decoupling mechanisms (Exhs. NG-PRM-1, at 5-6; NG-PRM-1, Sch. NG-PRM-3, at 2).

The seven remaining gas distribution companies included in the comparison group are: (1) AGL Resources, Inc.; (2) Atmos Energy Corporation; (3) New Jersey Resources Corporation; (4) Northwest Natural Gas; (5) Piedmont Natural Gas Company; (6) South Jersey Industries, Inc.; and (7) WGL Holdings, Inc. (Exhs. NG-PRM-1, at 5-6; NG-PRM-1, Sch. NG-PRM-3, at 2). National Grid submits that this group is the same group used by Bay State in D.P.U. 09-30 (Exh. NG-PRM-1, at 6). National Grid claims that the majority of the operations of the companies in its comparison group are regulated operations and that the group has 86 percent of its identifiable assets invested in regulated gas distribution operations (Exh. NG-PRM-Rebuttal-1, at 10).

The Attorney General also relied on a comparison group of companies for her analyses, based on the following selection criteria: (1) listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports; (2) listed as a natural gas utility in the Standard Edition of the Value Line Investment Survey; (3) receiving at least 50 percent of revenues from regulated gas operations; and (4) having an investment-grade bond rating by both Moody's and Standard & Poor's (Exh. AG-JRW at 12). The Attorney General's comparison group includes all of the companies in National Grid's comparison group, except that she excluded New Jersey Resources Corporation because that company receives only 42 percent of its revenue from regulated gas operations (Exh. AG-JRW at 54). In addition, the Attorney General's comparison group includes the following companies not included in National Grid's comparison group: (1) Laclede Group, Inc.; (2) NICOR, Inc.; and (3) Southwest Gas Corporation (Exhs. AG-JRW at 12-14; AG-JRW-4, at 1). The Attorney General claims that her comparison group receives 63 percent of its revenues from regulated gas operations (Exh. AG-JRW at 13).

2. Analysis and Findings

The Department has accepted the use of a comparison group of companies for evaluation of a cost-of-equity analysis when a distribution company does not have a common stock that is publicly traded. See D.P.U. 08-35, at 176-177; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 80-82 (2001); D.P.U. 92-78, at 95-96. The Department has stated that companies in the comparison group must have common stock that is publicly traded and must be generally comparable in investment risk. Western Massachusetts Electric Company, D.P.U. 1300, at 97 (1983).

In our evaluation of the comparison group used by National Grid, we recognize that it is neither necessary nor possible to find a group that matches the Companies in every detail. See 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 utilities will be in the comparison group, and then provides sufficient financial and operating data to discern the investment risk of the Companies versus the comparison group. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

In this case, given its proposal for a revenue decoupling mechanism, National Grid selected seven natural gas companies based on a number of criteria, including the criterion that each of the companies in the comparison group have a form of revenue stabilization or decoupling mechanism (Exhs. NG-PRM-1, at 5-6; NG-PRM-1, Sch. NG-PRM-3, at 2). National Grid's comparison group is identical to that used in D.P.U. 09-30. See D.P.U. 09-30, at 304-305. While the Department has accepted this comparison group in the past, a comparison group so narrow as to include such a small number of companies is at risk of including statistically significant anomalies. See Massachusetts-American Water Company, D.P.U. 1700, at 28 (1984); Oxford Water Company, D.P.U. 1699, at 26 (1984). National Grid accepts that, with a small sample of companies, anomalous results will carry a heavier weight than with a larger sample of companies (Tr. 11, at 1527-1528). The Attorney General agrees that, less data would make proxy groups more susceptible to anomalous results (Tr. 19, at 2727).

The Department expects more diligence on the part of the parties in recognizing that a small (narrowed) proxy group will not produce sufficiently reliable analysis required in determining a fair rate of return for the Companies. In this case, the Department will draw its conclusions about the relative risk characteristics of the Companies versus the members of the comparison groups presented by National Grid and the Attorney General. Going forward, the

Department expects parties to limit criteria to the extent necessary to develop a much larger comparison group than those presented here.

With respect to the comparison groups used in this case, the Department identifies and discusses two factors that we will take into consideration in determining the appropriate ROE for the Companies. First, National Grid's proposed decoupling mechanism is but one form of a wide range of revenue recovery mechanisms that the financial market and regulatory community consider to be some form of revenue stabilization mechanism. D.P.U. 09-39, at 348; D.P.U. 09-30, at 308; see also, D.P.U. 07-50-A at 72. Second, some of the holding companies in the comparison group are also involved in non-regulated businesses beyond gas distribution activities, potentially making these companies more risky, all else being equal, and in turn, more profitable than the Companies. D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 08-35, at 175; D.P.U. 07-71, at 135.

D. Return on Equity

1. National Grid's Proposal

a. Introduction

National Grid proposes to apply an 11.30 percent ROE for both Boston Gas-Essex Gas and Colonial Gas based on the results of three equity cost models: the DCF model, the risk premium model, and the CAPM (Exhs. WP NG-PRM-E; WP NG-PRM-G; WP NG-PRM-H). National Grid also applied a fourth model, the comparable earnings model (Exhs. NG-PRM-1, at 55; NG-PRM-1, Sch. NG-PRM-13). Based on its analyses, National Grid determined ROEs of 11.30 percent, 11.50 percent, 11.23 percent, and 12.95 percent using the DCF, risk premium model, CAPM, and comparable earnings model, respectively (Exh. NG-PRM-1, at 7). Based on the results of the DCF model, risk premium model, and CAPM, which National Grid characterizes as market-based models, National Grid determined an approximate average of 11.30 percent ROE (Exh. NG-PRM-1, at 7).

National Grid states that because all the companies in the comparison group have some form of revenue stabilization mechanism, the recommended ROE already reflects the impacts of decoupling on investors' expectations through the use of the market-based equity cost models (Exh. NG-PRM-1, at 11). National Grid's application of the DCF model, risk premium model, CAPM, and comparable earnings model are discussed in the following sections. The cost of equity impact of revenue decoupling is also discussed below.

b. Discounted Cash Flow Model

National Grid states that the DCF theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows, discounted at the appropriate risk-adjusted rate of return (Exhs. NG-PRM-1, at 25-26; WP NG-PRM-E at E1). National Grid notes that, in its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future appreciation (growth) of the investment (Exh. NG-PRM-1, at 26).

National Grid used a form of the DCF model referred to as the Gordon Model,[302] which assumes an infinite investment horizon and a constant growth rate (Exh. WP NG-PRM-E

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302 The Gordon model is expressed as: $k = D/P + g$, where k is the investor's required return on common equity, D is the dividend per share paid in the next period, P is the current market price per share of the common stock, D/P is the expected dividend

at E2). National Grid states that, according to the theory underlying the constant growth rate form of DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same rate absent any change in price-earnings multiples (Exh. WP NG-PRM-3, at E8). National Grid argues that the DCF model has limitations, including an element of circularity in the DCF method when applied in a rate case because investors' expectations depend upon regulatory decisions (Exh. NG-PRM-1, at 26). Due to this circularity, National Grid opines that the DCF model may not fully reflect the true risk of a utility (Exh. NG-PRM-1, at 26).

Regarding the dividend yield, National Grid calculated a yield of 4.25 percent based on the six-month average yields for the comparison group (Exh. NG-PRM-1, at 27). National Grid states that the use of a six-month average yield will reflect current capital costs while avoiding spot yields (Exh. NG-PRM-1, at 27). For the purpose of DCF calculations, however, National Grid states that the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments (i.e., higher expected dividends for the future) (Exh. NG-PRM-1, at 27). National Grid opines that this adjustment is equal to 0.14 percent, resulting in a dividend yield of 4.39 percent (Exh. NG-PRM-1, at 27).[303]

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yield, and g is the investor's mean expected long-run growth rate in dividends per share. See, e.g., D.P.U. 08-35, at 193; D.P.U. 07-71, at 125.

[303] In determining the adjustment to the dividend yield, National Grid states that it used three alternative methods and took the average of the results of the three methods to arrive at the 0.14 percent adjustment (Exh. WP NG-PRM-E at E7).

For the growth rate component of the model, National Grid estimated a 6.25 percent growth rate based on five-year forecasts (Exh. NG-PRM-1, at 35).[304] National Grid stated that in arriving at this estimate, it considered growth in financial variables including earnings per share, dividends per share, book value per share, and cash flow per share for its comparison group (Exhs. NG-PRM-1, at 28, 30; NG-PRM-1, Schs. NG-PRM-8, NG-PRM-9). National Grid submits that there is no need to count historical growth rates separately because historical performance is already reflected in analysts' forecasts, which represent an assessment of how the future will diverge from historical performance (Exh. NG-PRM-1, at 33). National Grid adds that, among the various alternative measures of growth rates identified above, earnings per share should receive the greatest emphasis because this measure is the primary determinant of investors' expectations concerning total returns (Exh. NG-PRM-1, at 33).

Using a dividend yield of 4.39 percent and a growth rate of 6.25 percent, National Grid's DCF model produces a ROE for the Companies' comparison group of 10.64 percent. (Exh. NG-PRM-1, at 38-39). National Grid, however, adjusted the DCF-determined cost of equity by adding 0.66 percent to represent a leverage adjustment, which recognizes that the expected ROE increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital

[304] National Grid claims that the company-specific growth analysis that it performed for the proxy group, which focused principally upon five-year forecasts of earnings per share growth rate, is consistent with the type of analysis that influences the total return expectations of investors (Exh. NG-PRM-1, at 31-32). National Grid adds that the five-year investment horizon associated with analysts' forecasts is consistent with the DCF model (Exh. NG-PRM-1, at 31-32).

structure (Exh. NG-PRM-1, at 38-39, 42-43). This adjustment results in a DCF cost of equity of 11.30 percent (Exh. NG-PRM-1, at 38-39, 42-43).

c. Risk Premium Model

National Grid states that the risk premium approach recognizes the required compensation, or premium, for the more risky common equity over the less risky secured debt position of a lender (Exh. WP NG-PRM-G at G1-G2). National Grid explains that in the case of senior capital represented by long-term debt, where a company contracts for the use of that debt capital, the cost rate is known with a high degree of certainty because the payment for the use of this capital is a contractual obligation and the schedule of future payments is known (Exh. WP NG-PRM-G at G1).

Alternatively, the cost of common equity is not fixed but varies with investors' perception of the risk associated with the common stock (Exh. WP NG-PRM-G at G1). National Grid states that the cost of equity according to the risk premium approach is equal to the interest on long-term corporate debt plus an equity risk premium (Exh. WP NG-PRM-G at G2).[305] National Grid acknowledges that, like the other models for cost of equity, the risk premium model has its limitations including the potential imprecision in assessing the future cost of debt and the measurement of the risk-adjusted common equity premium (Exh. NG-PRM-1, at 44). The methods that National Grid used in determining the interest and equity risk premium components of the risk premium model are described below.

[305] National Grid states that the formula for the risk premium model is: $k = i + RP$, where k is the cost of equity, i is the interest rate on long-term corporate debt, and RP is the equity risk premium (Exh. WP NG-PRM-G at G2).

Regarding the interest component, National Grid argues that a 6.0 percent yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds (Exh. NG-PRM-1, at 44, 46). National Grid submits that Moody's index and the Blue Chip Financial Forecasts ("Blue Chip") support the use of this figure (Exhs. NG-PRM-1, at 44; NG-PRM-1, Sch. NG-PRM-10). National Grid adds that this 6.0 percent rate is also supported by Blue Chip's long-term forecasts of interest rates (Exh. NG-PRM-1, at 46).

Regarding the equity risk premium, National Grid asserts that 5.50 percent is reasonable (Exh. NG-PRM-1, at 49). In arriving at this equity risk premium, National Grid first calculated the average risk differential between the Standard and Poors ("S&P") Public Utility index[306] and the yields for public utility bonds for the 1974 to 2007 period (6.08 percent) and the 1979 to 2007 period (6.37 percent) to arrive at a 6.23 percent average risk differential (Exhs. NG-PRM-1, at 47, 49; NG-PRM-1, Sch. NG-PRM-11, at 2; WP NG-PRM-G at G6-G7).[307] National Grid submits that this 6.23 percent average risk differential represents a reasonable risk premium for the S&P public utilities in this case (Exh. NG-PRM-1, at 49).

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306 The S&P Public Utility index is a widely recognized index that comprises 33 electric power and natural gas companies (Exh. NG-PRM-1, at 14, Sch. NG-PRM-4).

307 National Grid states that it considered alternative periods in its risk differential calculations including 1928 to 2007, 1952 to 2007, 1974 to 2007 and 1979 to 2007, with the 1928 to 2007 period showing the lowest and the 1952 to 2007 period showing the highest risk differential. It then excluded these lower and upper bounds from its calculations (Exhs. NG-PRM-1, at 47, 49; NG-PRM-1, Sch. NG-PRM-11, at 2; WP NG-PRM-G at G6).

National Grid adds that there are differences in risks associated with the S&P public utilities and its comparison group (Exh. NG-PRM-1, at 49). National Grid states that, based on its analysis of these differences in risks based on various market fundamentals including size, market ratios, common equity ratios, return on book equity, operating ratios, coverage quality of earnings, internally generated funds, and betas, a common equity risk premium of 5.50 percent represents a reasonable common equity risk premium for its comparison group (Exhs. NG-PRM-1, at 49; NG-PRM-1, Schs. NG-PRM-3, at 1, NG-PRM-4, at 1).[308] Using an interest component of 6.0 percent and an equity risk premium of 5.50 percent, National Grid concludes that its risk premium approach provides a cost of equity risk premium of 11.50 percent (Exh. NG-PRM-1, at 50).

d. Capital Asset Pricing Model

National Grid states that the CAPM attempts to describe the way prices of individual securities are determined in an efficient market where information is freely available and instantaneously reflected in securities prices (Exh. WP NG-PRM-H at H1). National Grid indicates that the CAPM postulates that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium, which is proportional to the non-diversifiable or systematic risk (or beta) of a security (Exh. WP NG-PRM-H at H1).[309] National Grid states

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308 National Grid notes that this 5.50 percent equity risk premium is 88 percent (5.50 percent divided by 6.23 percent) of the risk premium of the S&P public utilities and is reflective of the risk of its comparison group relative to the S&P public utilities (Exh. NG-PRM-1, at 49).

309 National Grid states that the formula for the traditional CAPM is: $k = Rf + \beta(Rm-Rf)$, where k is the cost of equity, Rf is the risk-free rate of return, (Rm-Rf) is

that the CAPM contains a variety of assumptions and shortcomings and should be used to complement other methods for measuring the cost of equity (Exh. NG-PRM-1, at 50).

In applying the CAPM, National Grid first determined that the risk-free rate should be equal to 4.75 percent (Exh. NG-PRM-1, at 53-54). National Grid states that this rate is based on the recent trends on yields on long-term U.S. Treasury bonds as well as on Blue Chip forecasts (Exhs. NG-PRM-1, at 53-54; NG-PRM-1, Sch. NG-PRM-12, at 2-4). National Grid argues that forecasts of interest rates should be emphasized at this time because the Federal Reserve System's suspension of reporting 30-year U.S. Treasury bond yields from March 2002 through January 2006 has affected the historic data (Exh. NG-PRM-1, at 53).

Next, National Grid calculated a market risk premium of 7.49 percent (Exh. NG-PRM-1, at 54). National Grid states that this rate is the average of a 6.05 percent market risk premium derived from the 2009 edition of the Ibbotson SBBI Classic Yearbook ("SBBI Classic Yearbook") and an 8.93 percent market risk premium derived from the Value Line and S&P 500 returns (Exhs. NG-PRM-1, at 54; WP NG-PRM-H at H6).

With regard to the systematic risk, or beta, National Grid first calculated an average beta of 0.65 for the comparison group from the beta for each company in the group as provided by Value Line (Exhs. NG-PRM-1, at 51; NG-PRM-1, Sch. NG-PRM-12, at 1). In order to develop a CAPM cost rate applicable to a capital structure measured and based on

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the market risk premium, and β is the systematic risk of the security (Exh. WP NG-PRM-H at H2).

book value, National Grid adjusted the Value Line market betas resulting in a leverage-adjusted beta for the comparison group of 0.74 (Exh. NG-PRM-1, at 52).[310]

National Grid contends that smaller companies tend to have higher capital costs than larger companies and, accordingly, that the CAPM could understate the cost of equity significantly, noting that in the SBBI Classic Yearbook, the returns for smaller capitalized stocks exceed the returns shown by the traditional CAPM (Exh. NG-PRM-1, at 54-55). National Grid notes that the comparison group has an average equity capitalization of $1.806 million, which falls within the low-capitalized group of firms as shown in the SBBI Classic Yearbook (Exh. NG-PRM-1, at 55). National Grid adds that the size premium for mid-capitalized firms based on that yearbook is 0.94 percent (Exh. NG-PRM-1, at 55). National Grid applied the 0.94 percent size premium that is applicable to the mid-capitalized group, as it contends that this is a conservative adjustment for the claimed size effect under the traditional CAPM (Exhs. NG-PRM-1, at 55). Using a risk-free rate of 4.75 percent, an adjusted beta of 0.74, a market risk premium of 7.49 percent, and the size adjustment of 0.94 percent, National Grid calculated a CAPM equity cost rate of 11.23 percent (Exh. NG-PRM-1, at 55).

e. Comparable Earnings Model

National Grid argues that because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insights into a fair rate of return (Exh. NG-PRM-1, at 55).

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310 A beta of less than 1.0 indicates that the security's price will be less volatile than that of the market.

According to National Grid, in order to identify the appropriate return within this framework of comparable earnings, it is necessary to analyze the returns earned by other firms whose prices are not subject to cost-based price ceilings, thereby avoiding circularity (Exh. NG-PRM-1, at 55-56).

National Grid states that there are two alternative approaches to implementing the comparable earnings approach. The first approach is to select another industry with comparable risks to the public utility in question. The results for all companies within that industry would serve as a benchmark for the public utility (Exh. NG-PRM-1, at 56). The second approach is to select parameters that represent similar risk characteristics for the public utility and the comparable risk companies (Exh. NG-PRM-1, at 56).

National Grid states that it adopted this second approach because the business lines of the comparable companies become unimportant. National Grid opines, however that the comparable risk companies should exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings and book ratios of other regulated firms (Exh. NG-PRM-1, at 56). Noting that a utility should have a return reasonably sufficient to assure investors' confidence in its financial soundness to enable it to raise the needed capital, National Grid submits that it is important to identify the returns earned by firms that compete for capital with a public utility (Exh. NG-PRM-1, at 56, citing Bluefield).

In applying the comparable earnings model based on the above-described approach, National Grid selected 25 non-regulated companies from the Value Line based on six screening criteria consisting of: timeliness; safety; financial strength; price stability; betas;[311] and technical rank (Exhs. NG-PRM-1, at 57; NG-PRM-1, Sch. NG-PRM-13, at 1). National Grid states that it used data over a ten-year period, comprising five years of historical realized returns and five-years of forecasted returns, a period which National Grid claims is sufficient to cover an average business cycle (Exh. NG-PRM-1, at 58).

National Grid states that, using median values, the historical rate of return on book common equity was 13.20 percent and the forecast rate of return as published by Value Line was 12.70 percent, for an average of 12.95 percent (Exhs. NG-PRM-1, at 58-59; NG-PRM-1, Sch. NG-PRM-13, at 2). Accordingly, National Grid states the rate of return on common equity produced by the comparable earnings model is 12.95 percent (Exh. NG-PRM-1, at 7, 59).

National Grid asserts that, unlike the DCF model, the risk premium model, and the CAPM, the results of the comparable earnings method can be applied directly to the book value capitalization because the nature of the analysis relates to book value (Exhs. NG-PRM-1, at 58). Accordingly, National Grid states that the comparable earnings approach does not have the potential misspecifications inherent in the market models[312] when the market capitalization and book value capitalization diverge significantly (Exh. NG-PRM-1, at 58).

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311 The betas for the twelve companies in the comparable earnings group range from 0.60 to 0.75 for an average of beta of 0.68 (Exh. NG-PRM-1, Sch. NG-PRM-13, at 1).

312 As described above, the Companies identified the DCF model, the risk premium model, and the CAPM as the appropriate market-based models to calculate its proposed ROE. The Companies then used the results from the comparable earnings model to confirm the reasonableness of the results of the market-based models (Exh. NG-PRM-1, at 59).

f. Cost of Equity Impact of Decoupling

As discussed in Section IV, above, National Grid proposed to implement a revenue decoupling mechanism for Boston Gas-Essex Gas and Colonial Gas (Exh. NG-LRK-1, at 7). National Grid states that its analyses of cost of equity as described above took into account the appropriate rate of return that should be used in the determination of the new base rates that will serve as a foundation for the implementation of revenue decoupling (Exh. NG-PRM-1, at 2). More specifically, National Grid notes that, because all of the companies in its comparison group have some form of revenue stabilization mechanism in place, its cost of equity analyses reflect the value that investors place on revenue stabilization and decoupling mechanisms (Exh. NG-PRM-1, at 11). Accordingly, National Grid states that, because its cost of equity recommendation already reflects any impacts of decoupling, no separate adjustment to ROE is warranted to capture any perceived decoupling impact (Exh. NG-PRM-1, at 11).

National Grid asserts that the relevant basis for comparison of risk is the market prices of the companies in the comparison group (Exh. NG-PRM-1, at 11). National Grid argues that, post-decoupling, it will continue to face variability in operating and capital costs that will contribute to earnings variability, although it does accept that decoupling reduces the volatility in utility revenues which, in turn, can support utility credit ratings (Exh. NG-PRM-1, at 11-12).

2. Attorney General's Proposal

a. Introduction

The Attorney General proposed a 7.07 percent WACC for Boston Gas-Essex Gas and a 7.34 percent WACC for Colonial Gas, representing the overall rate of return to be applied to the Companies' rate base to determine its total return on investment (Exhs. AG-JRW at 3; AG-JRW-1). This rate is based on: (1) a proposed capital structure that consists of 10.21 percent short-term debt, 39.92 percent long-term debt and 49.88 percent common equity for both Boston Gas-Essex Gas and Colonial Gas; (2) a proposed cost of long-term debt of 6.13 percent for Boston Gas-Essex Gas and 6.82 percent for Colonial Gas; (3) a proposed cost of short-term debt of 1.278 percent for both Boston Gas-Essex Gas and Colonial Gas; and (4) a proposed ROE of 9.0 percent for both Boston Gas-Essex Gas and Colonial Gas (Exhs. AG-JRW at 2, 5, 14-16; AG-JRW-1; AG-JRW-5).

In determining her proposed ROE, the Attorney General applied the DCF model and the CAPM on the market and financial data for her comparison group of nine gas distribution companies, as discussed above (Exhs. AG-JRW at 12, 24, 38-40; AG-JRW-4; AG-JRW-10; AG-JRW-11). Based on an 8.90 percent ROE derived from her DCF model and a 7.30 percent ROE derived from her CAPM analysis, the Attorney General concluded that the appropriate ROE for her comparison group was between 7.50 percent and 9.00 percent (Exh. AG-JRW at 49). The Attorney General, however, placed more weight on the results of her DCF analysis and concluded that the appropriate ROE for National Grid was 9.00 percent

(Exh. AG-JRW at 49-50). The components of the Attorney General's various models are discussed below.

b. Discounted Cash Flow Model

In arriving at her recommended 9.00 percent ROE for National Grid, the Attorney General applied the DCF model to her comparison group. The Attorney General applied the constant growth DCF model, but she also addressed the three-stage discounted or dividend-discount model with regard to the stages of a firm's growth, transition, and maturity (Exh. AG-JRW at 24-26).

In applying the constant growth DCF model, the Attorney General calculated a 4.30 percent average dividend yield for her comparison group. She derived this figure by averaging the June 2010 dividend yield of 4.20 percent and the six-month average dividend yield for the period ending June 30, 2010, of 4.40 percent, based on monthly data published by AUS Utility Reports (Exhs. AG-JRW at 29; AG-JRW-10 at 2).

In estimating the growth rate component of the constant growth DCF model, the Attorney General used Value Line historic and projected growth measures in earnings per share, dividends per share, and book value per share for her comparison group. She also used a sustainable growth rate that was measured by Value Line, average projected retention rate, and return on shareholder's equity. The Attorney General also used projected earnings per share growth rates from First Call, Zacks, and Reuters (Exh. AG-JRW-10, at 6).

The Attorney General's historical growth rate estimates for her comparison group, measured by the medians of the past five years of Value Line data, ranged from 2.0 percent to

6.50 percent with an average of 4.20 percent (Exhs. AG-JRW at 36; AG-JRW-10, at 3, 6). The Attorney General's projected growth rate estimates range from 3.0 percent to 4.0 percent, with an average of 3.50 percent (Exhs. AG-JRW at 36-37; AG-JRW-10, at 4, 6). The Attorney General's average prospective internal growth, or sustainable growth rate, for the proxy group as measured by Value Line's average projected retention rate and return on shareholder's equity is 4.70 percent (Exhs. AG-JRW at 37; AG-JRW-10, at 4, 6). The Attorney General claims that the internal growth is a primary driver of long-run earnings growth (Exhs. AG-JRW at 37). The median of the projected earnings per share growth rates from First Call, Zacks, and Reuters is 4.90 percent (Exhs. AG-JRW at 37; AG-JRW-10, at 5).

The average of each of these growth rate calculations for the Attorney General's comparison group is 4.40 percent. The Attorney General, however, decided to give more weight to the projected growth rate indicators and to prospective internal growth to arrive at a 4.50 percent growth rate which she then used in her DCF calculation (Exh. AG-JRW at 38).

The Attorney General also chose to adjust the current dividend yield by one-half the expected growth over the coming year as opposed to the coming quarter, arguing that it is common for analysts to adjust the dividend yield by some fraction of the long term expected growth rate (Exhs. AG-JRW at 30; AG-JRW-10, at 1). This adjustment resulted in a DCF-calculated ROE of 8.90 percent (Exhs. AG-JRW at 38; AG-JRW-10, at 1).

c. Capital Asset Pricing Model

The Attorney General states that the CAPM is a risk premium approach to gauging a firm's cost of equity capital (Exh. AG-JRW at 39). According to the Attorney General, the

CAPM is a theory of the risk and expected returns of common stocks (Exh. AG-JRW at 39). The Attorney General explains that, in the CAPM, two types of risk are associated with a stock: (1) firm-specific or unsystematic risk; and (2) market or systematic risk, which is measured by a firm's beta (Exh. AG-JRW at 39). According to the Attorney General's analysis, the only risk that investors receive a return for bearing is systematic risk (Exh. AG-JRW at 39).

The Attorney General states that the expected return on a company's stock, or equity cost rate (K), is equal to:

$$K = (Rf) + ß * [E(Rm) - (Rf)]$$

where E(Rm) represents the expected return on the overall stock market; (Rf) represents the risk-free rate of interest; [E(Rm)-(Rf)] represents the expected equity or market risk premium; and beta (β) is a measure of the systematic risk of an asset (Exh. AG-JRW at 39).

In applying the CAPM, the Attorney General first determined the risk-free rate to be equal to 4.25 percent based on the recent trend on yields on 30-year U.S. Treasury bonds (Exhs. AG-JRW at 41; AG-JRW-11, at 2). The Attorney General next determined an equity or market risk premium of 4.68 percent based on the average of a subset of studies derived from a large set of historical, forecast, and survey studies (Exhs. AG-JRW at 47; AG-JRW-11, at 5). In her analysis, the Attorney General eliminated all studies published before January 2, 2010, because most of these studies were published prior to the financial crisis of two years ago, and in order to assess the results of earlier equity risk premium studies that relied on data that went as far back as 50 years (Exhs. AG-JRW at 46-47; AG-JRW-11, at 5-6).

With regard to the systematic risk, or beta, National Grid calculated an average beta of 0.65 for her comparison group from the beta provided for each company by Value Line (Exhs. AG-JRW at 42; AG-JRW-11, at 3). Using a risk free rate of 4.25 percent, a beta of 0.65, and a market risk premium of 4.68 percent, the Attorney General calculated a CAPM-derived ROE of 7.30 percent (Exh. AG-JRW at 49).

d. Cost of Equity Impact of Decoupling

The Attorney General argues that the Department must recognize the risk reduction effect of National Grid's decoupling proposal in setting the Companies' allowed ROE (Exh. AG-JRW at 51). The Attorney General states that a number of state regulatory commissions that have adopted decoupling mechanisms have recognized the risk reduction associated with the adoption of the decoupling, and have made corresponding adjustments to authorized ROEs (Exh. AG-JRW at 51). The Attorney General identified these reductions by state, showing a range of reductions from ten basis points, in one case, up to 50 basis points, in most cases (Exh. AG-JRW at 51-52). According to the Attorney General, a reduction of 50 basis points to allowed ROE, may therefore be appropriate to recognize the risk reduction related to decoupling in this case (Exh. AG-JRW at 51-52).

The Attorney General claims that most of the companies in her comparison group have straight fixed/variable or decoupled rate designs for only some of their service territories and, therefore, her cost of capital analyses as described above do not take into account the full effect of decoupling in this case (Exh. AG-JRW at 52). Also, the median percentage of regulated gas revenues for the Attorney General's comparison group is 63 percent showing, she argues, that their associated risk reflects factors well beyond the operations of the regulated utility (Exh. AG-JRW at 52).

3. Positions of the Parties

a. Discounted Cash Flow Model

i. Attorney General

The Attorney General identified the historical and forecast measures of the growth rates for National Grid's comparison group (Exh. AG-JRW-10, at 3-5). Based on this information, the Attorney General argues that earnings per share forecasts of Wall Street analysts are upwardly biased and unrealistic measures of investors' expectations (Attorney General Brief at 175). Accordingly, the Attorney General asserts that National Grid's DCF growth rate, which is primarily based on the earnings per share forecasts of Wall Street analysts, is overstated and should be rejected (Attorney General Brief at 175; Attorney General Reply Brief at 52-54). Had National Grid considered all of the information in a balanced manner, the Attorney General argues that National Grid's DCF growth rate estimate would be in the 5.0 percent range rather than the 6.25 percent growth rate National Grid used (Attorney General Brief at 174).

The Attorney General also opposes National Grid's proposed 15-basis-points upward leverage adjustment on the DCF-determined ROE (Attorney General Brief at 180). The Attorney General contends that such an adjustment, which she characterized as a "market-to-book ratio adjustment," is unwarranted because the market value of a firm's equity exceeds the book value of equity when the firm is expected to earn more on the book value of the investment than investors require (Attorney General Brief at 180-181, citing Exh. AG-JRW-1, at 70-72).[313] The Attorney General argues that there is no change in leverage here because the financial statements and the fixed financial obligations remain the same, and that financial publications and investment firms report capitalization on a book-value and not on a market-value basis (Attorney General Brief at 180-181). The Attorney General contends that National Grid's claim that such a leverage adjustment is based on the research of Modigliani and Miller[314] is incorrect (Attorney General Brief at 181, citing Exh. AG-JRW-1, at 71). Further, the Attorney General claims that Department has rejected such a leverage adjustment in the past, and National Grid has not provided new evidence or arguments that should cause the Department to change or re-evaluate its previous findings (Attorney General Brief at 181, citing, e.g., D.T.E. 05-27).

ii. National Grid

National Grid reiterates that it relied on forecasted earnings per share information because investors are interested primarily in the future growth of their investments (National Grid Brief at VIII.9). National Grid argues that that the primary emphasis for the DCF growth

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313 The Attorney General claims that, although the Pennsylvania Public Utility Commission ("PaPUC") had previously accepted the leverage adjustment, the PaPUC did not include such a leverage adjustment in the recent Aqua Pennsylvania rate case (Attorney General Brief at 181, citing Aqua Pennsylvania, Pa PUC R-00072711 (2007)).

314 Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure (Exh. NG-PRM-1, at 42).

rate estimate should not be placed on historical growth rates because analysts use historical performance in developing their forecasts and, therefore, historical performance is already included in analysts' forecasts. Instead, National Grid argues that projected earnings per share should receive the greatest emphasis because earnings per share growth is the primary determinant of investors' expectations concerning their total returns in the stock market (National Grid Brief at VIII.9, citing Exh. NG-PRM-1, at 33; National Grid Reply Brief, at 83).

In addition, National Grid argues that it is necessary to incorporate a leverage adjustment into the simplified DCF model when it is applied to the capital structure used in utility ratemaking, which is calculated with book value weights rather than market value weights (National Grid Brief at VIII.10, citing Exh. NG-PRM-1, at 38). National Grid further argues that when a market-determined cost of equity developed from the DCF model is used, it reflects a level of financial risk that is different from the capital structure stated at book value. Accordingly, National Grid argues that that the leverage adjustment is necessary because it is a fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm plus compensation for having debt capital presented in the capital structure (National Grid Brief at VIII.10, citing Exh. NG-PRM-1, at 38-39, 42).

Further, National Grid contends that the Attorney General's DCF calculation contains significant errors (National Grid Brief at VIII.21). First, National Grid states that the Attorney General is incorrect in her assertion that the Department should not rely on forecasted growth rates made by analysts because they are overly optimistic and upwardly biased (National Grid

Brief at VIII.21, citing Attorney General Brief at 170, 174-175). Instead, as noted above, National Grid argues that projected earnings per share should receive the greatest emphasis (National Grid Brief at VIII.9; National Grid Reply Brief, at 83).

Second, in calculating her growth rate, National Grid argues that the Attorney General failed to convert the Value Line year-end forecasts to average book values (National Grid Brief at VIII.22, citing Attorney General Brief at 170). Third, National Grid argues that the Attorney General failed to include external growth in her growth rate calculation (National Grid Brief at VIII.22). Fourth, National Grid argues that the Attorney General improperly included the growth rates for dividends per share, book value per share and earnings retention in her DCF calculation (National Grid Brief at VIII.22-23).

Finally, National Grid argues that the Attorney General inappropriately uses a spot yield to determine the dividend yield for National Grid (National Grid Brief at VIII.23, citing Attorney General Brief at 169). National Grid claims that use of a spot yield is contrary to Department precedent because the Department generally uses a six-month average yield (National Grid Brief at VIII.23, citing D.T.E. 03-40, at 11). On these bases, National Grid advises that the Attorney General's DCF calculation is flawed and, therefore, should be rejected by the Department (National Grid Brief at VIII.23).

b. Capital Asset Pricing Model

i. Attorney General

The Attorney General recommends that the Department reject National Grid's CAPM-determined ROE because she contends that National Grid applied the model poorly

(Attorney General Brief at 175). The Attorney General claims that the Department has found that the assumptions underlying the CAPM are too "heroic" to make its application to a utility stock useful (Attorney General Brief at 175, citing D.T.E. 03-40, at 360; D.P.U. 96-50, at 125; D.P.U. 92-210, at 148-150; D.P.U 92-78, at 113; D.P.U. 88-67 (Phase I), at 184; D.P.U. 956, at 54-55).

ii. National Grid

National Grid states that, based on its CAPM analysis, it appropriately calculated an ROE of 11.23 percent (National Grid Brief at VIII.14; citing Exh. NG-PRM-1, at 55). Alternatively, National Grid criticizes the Attorney General's CAPM-determined ROE of 7.30 percent which it contends is based on an unrealistic market premium (National Grid Brief at VIII.23, citing NG-PRM-Rebuttal-1, at 17). For example, National Grid argues that if the S&P 500 had a DCF return of 7.0 percent, a dividend yield of 1.90 percent, and a growth rate of 5.10 percent, the DCF return for the S&P 500 would be less than the DCF return for gas utilities as calculated by the Attorney General (National Grid Brief at VIII.23-24; citing Exhs. AG-JRW-11, at 7; NG-PRM-Rebuttal-1, at 18-19). National Grid argues that a model producing this kind of anomalous result should not be relied upon by the Department (National Grid Brief at VIII.24).

c. Risk Premium Model

i. Attorney General

The Attorney General claims that National Grid's equity cost analysis using the risk premium model is flawed because it overstates the interest on utility bonds and, therefore, estimated an equity risk premium that is in excess of what investors expect (Attorney General Brief at 177).[315] On the interest component of the risk premium model which National Grid estimated by using the yield on utility bonds, the Attorney General identifies factors that inflate National Grid's results (Attorney General Brief at 177). First, the Attorney General asserts that long-term bonds are subject to interest rate risk, a risk which does not affect common stock because dividend payments are not fixed but tend to increase over time (Attorney General Brief at 177). Second, the Attorney General asserts that the base yield in the Companies' risk premium study is subject to credit risk because it is not default risk-free like an obligation of the U.S. Treasury (Attorney General Brief at 177). In addition, the Attorney General claims that because a bond's yield to maturity includes a premium for default risk, using such yield as the interest component in the risk premium model overstates investors' return expectations (Attorney General Brief at 177, citing Exhs. NG-PRM-1, at 44-46; AG-JRW-1, at 78-79).

Regarding the equity risk premium component of National Grid's risk premium analysis, the Attorney General notes that National Grid's analysis is based on the historical differences between the S&P Public Utility Index stock returns and public utility bond returns over various time periods from 1928 and 2007 using the geometric and arithmetic means and the median (Attorney General Brief at 177, citing Exh. WP NG-PRM-G). The Attorney General claims that such an analysis is flawed and overstates the equity risk premium (Attorney

315 The Attorney General claims that, although National Grid represented that the risk premium model is separate and distinct from the CAPM, the two approaches are essentially the same, noting that the cost of equity capital is equal to the yield on utility bonds plus an equity risk premium (Attorney General Brief at 176-177, citing Exhs. NG-PRM, at 44-50; WP NG-PRM-G).

General Brief at 177-78, citing Exhs. NG-PRM-1, at 49; AG-JRW at 73-81). More specifically, the Attorney General argues that the equity risk premium must be based on investors' expected premium and not simply based on an analysis of historical results, particularly given the difference between present and future market expectations and past market conditions (Attorney General Brief at 178).[316]

The Attorney General adds that the Department has reviewed and rejected a risk premium analysis many times in the past (Attorney General Brief at 180, citing, e.g., D.T.E. 03-40, at 359; D.P.U. 96-50, at 128; D.P.U. 95-40, at 97; D.P.U. 93-60, at 261; D.P.U. 92-111, at 265-266; D.P.U. 92-210, at 138-139; D.P.U. 90-121, at 171). The Attorney General claims that, in each of the cited cases, the Department found that the risk

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[316] The Attorney General identified what she claims to be additional flaws in National Grid's calculation of the equity risk premium, including: (1) historical bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past, thereby resulting in the equity risk premium being biased upwards; (2) the use of the arithmetic mean over the geometric mean to calculate returns biases the equity risk premium upwards when a study covers more than one period as done by the Companies; (3) a large error in measuring the equity risk premium derived from historical returns as shown by the standard deviation equal to 20.6 percent around an average risk premium of 6.5 percent; (4) unattainable and biased historical stock returns using a method that incorrectly assumes that portfolios can be rebalanced monthly at zero cost; (5) a "survivorship" upward bias because companies that survived are counted in the return calculations, while those that did not survive are not included in the return calculations; (6) the U.S. stock market survivorship bias resulting in historical stock returns being overstated as measures of expected returns because the U.S. markets have not experienced the disruptions of other major markets around the world; (7) current market conditions are significantly different from those of the past such that historical data does not provide a realistic or accurate barometer of investors' current expectations; and (8) changes in risk and return in the markets associated with the dramatic change in the risk and return relationship between stocks and bonds where bonds have increased in risk relative to stocks, thus lowering the equity risk premium (Attorney General Brief at 178-180, citing Exh. AG-JRW-1, at 73-81).

premium model overstates the amount of company-specific risk and, therefore, overstates the cost of equity (Attorney General Brief at 180, citing D.T.E. 03-40, at 359; D.P.U. 96-50, at 128; D.P.U. 95-40, at 97; D.P.U. 93-60, at 261; D.P.U. 92-111, at 265-266; D.P.U. 92-210, at 138-139; D.P.U. 90-121, at 171). The Attorney General asserts that because National Grid has provided no new analyses and no new argument in this regard, the Department should reject National Grid's risk premium analysis (Attorney General Brief at 180).

ii. National Grid

National Grid states that the Department has not consistently rejected the risk premium model but, instead, has treated it as a supplemental approach to the DCF model (National Grid Brief at VIII.11, citing D.P.U. 07-71, at 137). Therefore, National Grid argues that the Department should at least consider the results of the risk premium model to supplement the calculation of National Grid's ROE (National Grid Brief at VIII.11).

d. Comparable Earnings Model

i. Attorney General

Like the risk premium model, the Attorney General states that the Department has repeatedly rejected the comparable earnings approach (Attorney General Brief at 176; citing D.T.E. 03-40, at 360-361; D.P.U. 96-50, at 131-132; D.P.U. 92-250, at 160-161; D.P.U. 92-111, at 280-281; D.P.U. 92-210, at 155; D.P.U. 905, at 48-49). According to the Attorney General, the Department specifically rejected National Grid's use of the comparable earnings approach as unreliable because the earned return on common equity did not necessarily equal the Companies' cost of capital (Attorney General Brief at 176, citing D.P.U. 905, at 48-49; D.P.U. 1991, at 56).

The Attorney General further argues that, because National Grid has not evaluated the market-to-book ratios for the companies used in its comparable earnings approach, it cannot ascertain whether the past and projected returns on common equity are above or below investors' requirements. Further, it has no way to know whether the companies' ROEs are excessive because it cannot determine if the market-to-book ratios for these companies are greater than 1.0 (Attorney General Brief at 176, citing Exh. AG-JRW at 91-92).

The Attorney General claims that National Grid has provided no reason in this case for the Department to change its well-founded findings with respect to the comparable earnings approach (Attorney General Brief at 176). Accordingly, the Attorney General argues that the Department should reject National Grid's comparable earnings analysis because its results are unreliable (Attorney General Brief at 176).

ii. National Grid

National Grid states that the comparable earnings approach recognizes that, because regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return (National Grid Brief at VIII.14). National Grid also explains that the firms selected for its comparable earnings approach are companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided (National Grid Brief at VIII.14).

Contrary to the suggestions of the Attorney General, National Grid argues that it did not directly rely on the comparable earnings approach in recommending an ROE (National Grid Brief at VIII.14, citing Exh. NG-PRM-1, at 7, 59; Attorney General Brief at 176). Rather, National Grid states that it used the comparable earnings approach to gauge the reasonableness of the results produced by the market-based models (National Grid Brief at VIII.14).

e. Cost of Equity Impact of Decoupling

i. Attorney General

As noted above, the Attorney General argues that the Department should recognize the risk reduction effect of National Grid's rate design proposal (Attorney General Brief at 166-167 n.54, citing Exh. AG-JRW at 51). The Attorney General submits that a number of regulatory commissions nationwide, which have adopted decoupling mechanisms for electric and gas companies, have recognized the risk reduction associated with the adoption of decoupling (Attorney General Brief at 166-167 n.54). Further, the Attorney General states that using appropriate stock market-based analyses and adjusting for the Companies' lower investment risk associated with decoupling, the Department should use a cost of equity no higher than 9.0 percent to determine the Companies' revenue requirements in this case (Attorney General Brief at 166-167).

ii. National Grid

National Grid argues that the Department must allow the Companies a return commensurate with the returns for similar enterprises having corresponding risks (National

Grid Brief at VIII.4, citing Attorney General v. Department of Public Utilities, 392 Mass. at 266, quoting Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)). National Grid states that it's proposed ROE is based on a group of proxy companies that have corresponding risks, given that these companies have already implemented revenue stabilization mechanisms that account for any change in risk that the Companies will experience with the implementation of revenue decoupling (National Grid Brief at VIII.4, citing Exh. NG-PRM-1, at 5-6, 11; AG-13-13, Att.). National Grid claims that any recommendation from any party to reduce the Companies' ROE as a result of decoupling is based solely on speculation and conjecture (National Grid Brief at VIII.4).

Further, National Grid argues that the relevant analysis in determining whether the implementation of revenue decoupling should have any impact on the authorized ROE is not properly made by looking at the Companies' "risk" with or without the decoupling mechanism in place (National Grid Brief at VIII.15). Rather, the proper analysis is to compare investors' perceptions of the risk profiles of Boston Gas-Essex Gas and Colonial Gas with decoupling relative to the comparison group of companies used in its analyses (National Grid Brief at VIII.15). According to National Grid, investors are aware that companies in its comparison group have revenue-stabilization mechanisms and, therefore, investors have priced the stocks of these companies to account for the impact of those mechanisms (National Grid Brief at VIII.16). Accordingly, National Grid argues that any further downward adjustment to account for the implementation of revenue decoupling would have the result of double-counting the impact on ROE (National Grid Brief at VIII.16).

4. Analysis and Findings

a. Introduction

As support for its recommended ROE of 11.30 percent for both Boston Gas-Essex Gas and Colonial Gas, National Grid applied the DCF model, the CAPM, and the risk premium model using the financial data of seven gas utility companies that constitute its chosen comparison group (Exhs. NG-PRM-1, at 5-6; NG-PRM-1, Sch. NG-PRM-3, at 1-2).[317] Likewise, to arrive at her recommended ROE of 9.0 percent for both Boston Gas-Essex Gas and Colonial Gas, the Attorney General applied the DCF model and the CAPM using the financial data of nine gas utility companies that constitute her chosen comparison group (Exhs. AG-JRW at 12; AG-JRW-4, at 1-2; AG-JRW-10; JRW-11).

All companies in National Grid's proxy group employ some form of revenue stabilization or revenue decoupling mechanism for at least some element of their regulated businesses (Exhs. NG-PRM-1, at 11). The Attorney General did not use a revenue stabilization mechanism as a criterion for selection of her comparison group (Exh. AG-JRW at 12-13). Rather, her comparison group met the following selection criteria: (1) they were listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports; (2) they were listed as a natural gas utility in the Value Line; (3) they receive at least 50 percent of their revenues from regulated gas operations; and (4) they have an investment-grade bond rating by Moody's and S&P (Exh. AG-JRW at 12-13).

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[317] Although National Grid also applied the comparable earnings model using the financial data of 25 non-regulated companies, it states that the results of this model were used only as a check on the results of the Companies' market-based ROE models (Exhs. NG-PRM-1, at 59; NG-PRM-1, Sch. NG-PRM-13, at 1-2).

As we noted above, in our evaluation of a comparison group, we recognize that it is neither necessary nor possible to find a group that matches National Grid in every detail. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136. Therefore, we have accepted National Grid's as well as the Attorney General's comparison groups of gas utility companies with publicly traded stocks as a basis for their costs of capital proposals, but will consider the investment risk of the Companies versus the comparison groups when determining the appropriate ROE for the Companies.

As both National Grid and the Attorney General agreed, comparison groups that include a small number of companies are more likely to produce anomalous results (Tr. 11, at 1527-1528; Tr. 19, at 2727). In this case, the Department will draw its conclusions about the relative risk characteristics of the Companies versus the members of the comparison groups presented by National Grid and the Attorney General. Going forward, parties are expected to recognize and respond to the fundamental financial precept that a small proxy group will not produce an analysis sufficiently reliable in determining outcomes of rate cases such as this one. See D.P.U. 1700, at 28; D.P.U. 1699, at 26. Decoupling is not yet widely adopted and, to the extent it has been adopted in other jurisdictions, implementation has been achieved through various methods (see, e.g., Exh. Rebuttal JRW-2). Accordingly, it may not be possible to limit a comparison group to only those entities that have implemented various decoupling mechanisms. In the future, the Department expects parties to limit their selection criteria to the extent necessary and appropriate to develop a larger proxy group than those presented here.

b. Discounted Cash Flow Model

The constant growth DCF, or the Gordon model, used by National Grid and the Attorney General has a number of very restrictive assumptions (Exhs. NG-PRM at 26-30; WP NG-PRM-E at E1-E4). For example, the constant growth rate form of the DCF model assumes that future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same rate absent any change in price-earnings multiples (Exh. NG-PRM-1, at 28). In addition, the DCF model has other limitations including an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions (Exh. NG-PRM-1, at 26). The Department is not persuaded by the validity of the assumptions that underlie the constant growth rate DCF model. See D.P.U. 08-35, at 199. Accordingly, we will consider these model limitations in evaluating the DCF-determined ROEs presented in this proceeding.

Regarding National Grid's proposed leverage adjustment, which increases by 0.66 percent its DCF-determined ROE, National Grid argues that this adjustment is necessary to account for the difference in financial risk between the equity ratio measured at market value and the equity ratio measured at book value (Exh. NG-PRM-1, at 36-39). Specifically, National Grid claims that the 0.66 percent upward adjustment reflects the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure, which contains lower financial risk (Exh. NG-PRM-1, at 38).

The Department has consistently rejected a DCF leverage adjustment. D.T.E. 05-27, at 297-298; D.T.E. 03-40, at 357-359; D.T.E. 01-56, at 105-106; D.P.U. 906, at 100-101; Eastern Edison Company, D.P.U. 837/968, at 49 (1982). Based on our review of the record in this case, we are not persuaded to re-evaluate our previous finding on this issue. National Grid's proposed leverage adjustment relies on a comparison between book and market capitalization and, thus, contains the same defects as the Department has previously identified including insufficient consideration of the multiplicity of factors that affect investor decisions. See, e.g., D.T.E. 01-56, at 105-106. In addition, although National Grid claims that such a leverage adjustment is applied to account for the difference in financial risks between the equity ratio measured at market value and the equity ratio measured at book value, we are not persuaded that an investors' market assessment of the underlying risks of a regulated utility does not consider such difference between book and market capitalization. Accordingly, the Department rejects National Grid's proposed leverage adjustment.

c. Risk Premium Model

The Department has repeatedly found that a risk premium analysis could overstate the amount of company-specific risk and, therefore, overstate the cost of equity. See D.P.U. 90-121, at 171; D.P.U. 88-135/151, at 123-125; 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 stocks in investors' portfolios and, therefore, the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183.

The risk premium model, like the other equity cost models used by National Grid, suffers from a number of limitations including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium (Exhs. NG-PRM-1, at 44; WP NG-PRM-G at G1). The Department has acknowledged the value of risk premium analysis as a supplemental approach to other ROE models and accorded it, at best, limited weight in our determination of the cost of equity. D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86. As it suffers from the same limitations previously noted, the Department finds that National Grid's risk premium analysis tends to overstate the required ROE for the Companies.

d. Capital Asset Pricing Model

The Department has rejected the use of the traditional CAPM as a basis for determining a utility's cost of equity because of a number of limitations, including questionable assumptions that underlie the model. D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54.[318] The Department notes that National Grid made two adjustments in its analysis when applying the CAPM using the average financial and market data of the companies in its comparison group.

318 In D.P.U. 08-35, at 207 n.131, the Department identified the following questionable assumptions used in the CAPM: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period.

First, National Grid adjusted upward the average beta coefficient for the proxy group from 0.65 to 0.74 (Exh. NG-PRM-1, at 52). Because the cost of equity under the CAPM is equal to the risk-free rate of return plus the product of the beta and the market risk premium, such adjustment correspondingly increases the resulting ROE (Exhs. NG-PRM-1, at 55; WP NG-PRM-H at H2). As in our analysis of the leverage component of National Grid's DCF model, the Department finds that the use of leveraged betas in National Grid's CAPM overstates the required ROE for the Companies. See D.P.U. 09-30, at 358-359.

Second, National Grid added 0.94 percent to the ROE resulting from its application of the CAPM (Exh. NG-PRM-1, at 54-55). National Grid argues that this adjustment appropriately accounts for the tendency of the CAPM to understate the cost of equity for relatively small firms (Exh. NG-PRM-1, at 54-55). The Department has previously rejected this adjustment based on the size premium determined in the SBBI Classic Yearbook because of our concerns with the comparability of the entities contained therein to a comparison group, as well as some of the limitations resulting from the use of traditional CAPM to determine size premiums. D.P.U. 08-35, at 216-217.[319] National Grid has not presented any new evidence that would serve as a basis for the Department to re-evaluate our previous findings here. Accordingly, the Department rejects National Grid's proposed adjustment to CAPM. Based on the above considerations, the Department finds that the traditional CAPM would have a limited

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[319] In D.P.U. 08-35, at 211-212, New England Gas Company used the 2008 edition of the SBBI Classic Yearbook. In this case, the Companies based its proposed size premium adjustment on the 2009 edition of the SBBI Classic Yearbook (Exh. NG-PRM-H at H5).

value in determining the Companies' ROE in this case and tends to overstate the Companies' required ROE. The Attorney General's CAPM analysis has similar limitations.

e. Comparable Earnings Model

The Department has generally rejected the results of the comparable earnings model analysis because the risk criteria provided were not sufficient to establish the comparability of the non-regulated group of firms with the distribution company being considered. D.P.U. 08-35, at 210; D.T.E. 01-56, at 116. Although the average adjusted and unadjusted betas of the comparable earnings model comparison group of 25 non-price regulated companies are comparable to the average adjusted and unadjusted betas of the seven companies in National Grid's comparison group, there are other risk criteria that must be evaluated as the basis for selecting an appropriate comparison group of companies for use in this model. D.P.U. 08-35, at 210; D.T.E. 01-56, at 116.

In addition, the Department has found that the use of the beta as a criterion in selecting a comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.P.U. 96-50 (Phase I) at 132. Moreover, the beta, which is a measure of risk based on the CAPM, reflects the limitations of that model, including its unrealistic assumptions as identified above. We note that National Grid used the results from the comparable earnings model only to confirm the results of the market-based models (Exh. NG-PRM-1, at 59). For all of these reasons, the Department will not rely on the results of the comparable earnings model analysis as a basis for determining the allowed ROE for the Companies.

f. Cost-of-Equity Impact of Decoupling

In D.P.U. 07-50-A, the Department stated that, because decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales arising from energy efficiency, demand-response, and distributed resources initiatives, by definition decoupling reduces earnings volatility. D.P.U. 07-50-A at 72; D.P.U. 07-50, at 1-2. The Department added that such reduction-in-earnings volatility should reduce risks to shareholders and, thereby, should serve to reduce the required ROE. D.P.U. 07-50-A at 72-73.

The Department stated, however, that it will consider the impact of a decoupling mechanism on a distribution company, along with all other factors affecting that company's required ROE in the context of a rate proceeding, where the evidence and arguments may be fully tested. D.P.U. 07-50-A at 74. We consider below the impact of the Companies' revenue decoupling mechanism on its allowed ROE.

The Attorney General asserts that the implementation of National Grid's revenue decoupling mechanism as proposed in this case will shift risks from shareholders to ratepayers (Attorney General Brief at 29). Further, as noted earlier, the Attorney General maintains that a number of regulatory commissions that have adopted decoupling mechanisms for electric and gas companies have recognized the risk reduction associated with the adoption of decoupling (Attorney General Brief at 166 n.54). Based on her survey of these adjustments, to recognize this reduction in risk, the Attorney General recommends that the Department make a 50-basis-point reduction to the Companies' ROE (Exh. AG-JRW at 51).

Under the revenue decoupling mechanism approved in this proceeding, at the end of each annual period National Grid will compare the difference between the annual target base distribution revenue with the actual collected base distribution revenues, and refund or collect the difference through the revenue reconciliation component of the revenue decoupling plan (Exh. NG-SFT-1, at 30-31). Because the Companies will recover fully during the ensuing years its approved base distribution revenue requirement (including a component return on rate base), we find that the decoupling revenue adjustment will result in rate year distribution revenues that will closely reflect the distribution revenue requirement approved in this base rate proceeding.

The Department has previously rejected proposals for adjusting rate year revenues due to deviations in weather. See, e.g., D.T.E. 03-40, at 407, 423; D.P.U. 92-210, at 157-172, 199; D.P.U. 92-111, at 18-33, 60-61. In rejecting those proposals, the Department found that they would result in a less risky profile for the Companies, and that any resulting reduction in risk of equity investments should be shared with ratepayers through a commensurate adjustment in a company's rate of return on capital. D.T.E. 03-40, at 423; D.P.U. 92-210, at 199; D.P.U. 92-111, at 60-61. In the instant case, where changes in sales arising from all factors, including weather, are decoupled from the Companies' approved base distribution rates, we reaffirm the above findings regarding the resulting lowered risk profile of a company and the resulting impact on its cost of equity. See D.P.U. 09-30, at 369. In addition, based on the specific record in this case, we confirm the Department's generic finding in D.P.U. 07-50-A at 72-73 that, because decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales arising from energy efficiency, demand-response, and distributed resources initiatives, such a reduction in revenues and earnings volatility should reduce risks to shareholders and, thereby, serve to reduce the required ROE. In sum, we find that the revenue decoupling mechanism that we have approved in this case will reduce the variability of the Companies' revenues and, accordingly, reduce its risks and its investors' return requirement. See D.P.U. 09-30, at 367, 371-372; D.P.U. 07-50-A at 72-73.

As noted above, all companies in National Grid's comparison group have some form of decoupling or revenue stabilization mechanisms (Exh. NG-PRM-1, at 11). A review of the various mechanisms indicates that there is a wide range of approaches used for revenue stabilization from one regulatory jurisdiction to another. Thus, the fact that the comparison groups of companies have revenue stabilization mechanisms does not mean that the comparison groups fully match the risk profile of the Companies with respect to their proposed decoupling mechanism. Accordingly, we do not accept National Grid's argument that there is no need to consider the equity cost impact of decoupling because the comparison groups use some form of revenue stabilization mechanism, and in fact, we are not convinced that the comparison groups fully capture the risk-reducing impact of the Companies' decoupling mechanism.

As noted above, as a basis for her proposed 50-basis-points reduction to the Companies' ROE, the Attorney General surveyed the ROE downward adjustments by a number of regulatory commissions indicating a range of reductions from of ten basis points to 50 basis points (Exh. AG-JRW at 51-52). While we will accord this evidence appropriate weight, we recognize that those commissions' decisions were based on the specific underlying facts of those cases. Thus, we cannot mechanically apply a 50-basis-point reduction for the change in investors' risks perception associated with the Companies' implementation of revenue decoupling. We will, instead, examine the specific risk profiles of the Companies and the specific features of the revenue decoupling proposal we are approving today to arrive at the appropriate determination of the effect on risk on National Grid's required ROE.

g. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942) ("Hope"). The allowed ROE should preserve the Companies' 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.

In support of its calculations of an appropriate ROE, National Grid has presented analyses using the DCF model, risk premium model, and CAPM using the financial data of a comparison group of seven gas distribution companies. The Attorney General has presented her own analyses using the DCF model and CAPM using the financial data of a comparison group of nine gas distribution companies. The use of these empirical analyses in this context, however, 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. Western Massachusetts Electric Company, D.P.U. 18731, at 59

(1977). Each level of judgment to be made contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As stated above, the record demonstrates that all these equity cost models suffer from a number of simplifying and restrictive assumptions. Applying them to the financial data of a comparison group of companies could provide results that may not be reliable for the purpose of setting the Companies' ROE. In the case of the DCF model, for example, which was used by both National Grid and the Attorney General, we note the limitations of the DCF analysis, including the simplifying assumptions that underlie the Gordon model and the inherent limitations in comparing the Companies to publicly-traded companies. As stated above, we reject National Grid's attempt to adjust the DCF-determined ROE of 10.64 percent by adding a leverage adjustment of 0.66 basis points. Moreover, the CAPM analyses relied upon by National Grid and the Attorney General are also flawed, both from the limitations of traditional CAPM theory as well as the determination of beta.

As noted above, we recognize that the revenue decoupling mechanism we have approved in this case will reduce the variability of the Companies' revenues and, accordingly, reduce their risks and their investors' return requirement. See D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although the companies in the comparison groups used by National Grid and the Attorney General have some forms of revenue stabilization or decoupling mechanisms, the degree of revenue stabilization varies among the companies in the comparison groups and, on the whole, is not as comprehensive as the decoupling mechanism approved for the Companies in this Order.

Further, we note that a portion of the revenues of the gas companies in National Grid's and the Attorney General's comparison groups are derived from non-regulated and competitive lines of business that could skew the risk profile comparability with the regulated gas distribution operations of the Companies in a manner that, all else being equal, would tend to overstate the comparison groups' risk profile relative to that of the Companies. Therefore, in applying this comparability standard, we will consider such risk differentials in determining the Companies' allowed ROE.

Therefore, 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. D.P.U. 08-35, at 219-220; D.T.E. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978). The Department must account for additional factors specific to a company itself that may not be reflected in the results of the models.[320]

In this case, one factor we have considered in determining the allowed ROE relates to National Grid's use of fully reconciling mechanisms to recover certain costs outside of base

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[320] For example, the Department has set ROEs that are at the higher or lower end of the reasonable range based on above average or subpar management performance. See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 134-138 (2008); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 231 (2002); Cambridge Electric Light Company, D.P.U. 92-250, at 161-162 (1993); Massachusetts Electric Company, D.P.U. 92-78, at 115 (1992); Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 225 (1991).

rates. National Grid presently has in place fully reconciling mechanisms for a range of expense categories, including gas costs, supply-related bad debt, and an LDAC that fully reconciles costs related to demand side management and residential assistance adjustments. Boston Gas also has a fully reconciling pension and PBOP mechanism.[321] As a result of this Order, National Grid will retain these reconciling mechanisms and implement revenue decoupling, along with a fully reconciling TIRF and an Attorney General consultant cost recovery mechanism. Also, Colonial Gas will receive a fully reconciling pension and PBOP mechanism. The presence of these fully reconciling mechanisms covering a significant portion of the Companies' expenses will result in a lower risk for National Grid.

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 9.75 percent is within a reasonable range of rates that will preserve the Companies' financial integrity, will allow it to attract capital on reasonable terms, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the Companies' various methods for determining its proposed rate of ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

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321 The Boston Gas pension and PBOP mechanism will extend to Essex Gas as well (see Section X.F.3 above).

XII. RATE STRUCTURE

A. Marginal Costs

1. Introduction

The use of a marginal cost study in ratemaking provides consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on the marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 09-30, at 378; D.P.U. 08-35, at 227; D.P.U. 07-71, at 159. According to National Grid, its marginal cost study was developed based on a set of Department directives and standards that have been established in several Department decisions, most recently in D.P.U. 09-30 (Exh. NG-JDS-1, at 4-5). National Grid prepared a marginal cost study for the combined Boston Gas-Essex Gas entity and a marginal cost study for the combined Colonial Gas entity (Exh. ND-JDS-1, at 2-3; NG-JDS-1-1-BGC through NG-JDS-1-5-BGC; NG-JDS-1-1-COL through NG-JDS-1-5-COL).

2. Marginal Cost Studies

a. Boston Gas-Essex Gas

National Grid states that, consistent with Department precedent, it limited the Boston Gas-Essex Gas marginal cost study to the estimation of capacity-related distribution costs (Exh. NG-JDS-1, at 7). Specifically, National Grid estimated the marginal cost of capacity-related distribution plant, marginal capacity-related operations expense, marginal capacity-related maintenance expense, and three ancillary components: marginal general plant, marginal administrative and general, and marginal materials and supplies expense (Exh. NG-JDS-1, at 7).

In preparing the marginal cost studies, National Grid collected various plant, expense, and customer data from Boston Gas' annual reports to the Department (Exh. NG-JDS-1, at 8). From this data, National Grid created four types of new data series by: (1) transforming expense data to remove price inflation; (2) separating distribution O&M expenses into capacity- or customer-related expenses; (3) normalizing peak demands; and (4) developing four subsets of measure to reflect the nature and condition of the distribution system (Exh. NG-JDS-1, at 8). Further, National Grid created and used data series in the regression analysis to measures the annual change in normalized peak day demand that would explain Boston Gas' annual capacity-related distribution plant additions (Exh. NG-JDS-1, at 9).

National Grid combined Boston Gas and Essex Gas data to calculate the fixed carrying charge rates as well as to calculate marginal costs by class (Exh. NG-JDS-1, at 5, 17). National Grid, however, excluded Essex Gas data in the regression analysis. National Grid explains that, although Boston Gas and Essex Gas are integrated operationally, the integrated utility more closely resembles Boston Gas on a stand-alone basis because Boston Gas is substantially larger than Essex Gas (Exh. NG-JDS-1, at 5). Thus, National Grid concluded that the Boston Gas marginal cost models are the best estimate of the marginal costs that would apply on a going-forward basis (Exh. NG-JDS-1, at 5). Further, National Grid states that there were 30 years of data available to estimate Boston Gas's distribution capacity-related cost structures but substantially less available data for Essex Gas (Exhs. NG-JDS-1, at 5-6; DPU-16-22).[322]

The regression analyses presented by National Grid contain a variety of independent explanatory variables (Exhs. NG-JDS-1-1-BGC through NG-JDS-1-5-BGC; NG-JDS-1-1-COL through NG-JDS-1-5-COL). Included among them are several dummy variables that represent various stages in the Companies' history (Exhs. NG-JDS-1-1-BGC through NG-JDS-1-5-BGC; NG-JDS-1-1-COL through NG-JDS-1-5-COL).

As noted above, National Grid calculated the fixed carrying charge rate using data for both Boston Gas and Essex Gas (Exh. NG-JDS-1, at 5, 17). The fixed carrying charge rate is used to convert the marginal cost of plant additions from a cost that represents the estimated marginal investments into the levelized annual cost of that investment (Exh. NG-JDS-1, at 16). National Grid selected a version of the fixed carrying charge calculation known as the "Economist's Fixed Carrying Charge Rate" because it accounts for the reduced value of the revenue requirements in future years due to price inflation (Exh. NG-JDS-1, at 16-17).

[322] National Grid states that combined Boston Gas and Essex Gas data were used in a very limited manner, to calculate the fixed carrying charge rate because the necessary data were only available on a combined basis (Exhs. NG-JDS-1, at 17; DPU-16-22). According to National Grid, using Boston Gas data rather than a combination of Boston Gas and Essex Gas data to prepare estimates of marginal costs significantly improves the quality of the analysis because issues associated with missing Essex Gas data could be avoided (Exh. DPU-16-22). Further, National Grid contends that using combined Boston Gas and Essex Gas data to prepare the fixed carrying charge rate improves the quality of the analysis because the fixed carrying charge rate derived from the combined data provides the most accurate representation of the levelized annual cost of distribution plant investment (Exh. DPU-16-22).

National Grid estimated the total loss-adjusted marginal distribution cost of service to be $92.69 per decatherm ("Dth") of demand for Boston Gas-Essex Gas (Exhs. NG-JDS-1, at 18; NG-JDS-1-5-BGC). This estimate incorporates lost and unaccounted for gas (Exh. NG-JDS-1, at 18). Based on this estimate, National Grid developed class specific marginal cost rates per Dth for Boston Gas-Essex Gas (Exhs. NG-JDS-1, at 18; NG-JDS-1-5-BGC at 2, 3).

b. Colonial Gas

National Grid states that it followed the Department's standards in performing Colonial Gas's marginal cost study, with two exceptions: (1) due to the unavailability of certain data, the regression equations are based on 28 years of data instead of 30 years of data; and (2) the materials and supplies marginal loading factor is based on a ratio of materials and supplies expenses to total utility plant, instead of regression analysis (Exh. NG-JDS-1, at 18). According to National Grid, despite its various attempts to develop the materials and supplies expenses loading factor using regression models, it was unable to develop a regression model that demonstrated a meaningful relationship between materials and supplies and utility plant (Exh. NG-JDS-1, at 23) The Colonial Gas marginal cost study is based on combined data from the Lowell and Cape Cod divisions (Exh. NG-JDS-1, at 19).

National Grid conducted a marginal cost study for Colonial Gas that it states was substantially similar to the marginal cost study described above for Boston Gas-Essex Gas (Exhs. NG-JDS-1, at 19-25; NG-JDS-1-1-COL through NG-JDS-1-5-COL). In developing its estimates for Colonial Gas, National Grid used dummy variables to explain behavior not explained by the data alone (Exhs. NG-JDS-1-1-COL through NG-JDS-1-3-COL).

National Grid estimated the total loss-adjusted marginal distribution cost of service to be $87.69 per Dth of demand plus $0.1891 per Dth of sendout for Colonial Gas (Exhs. NG-JDS-1, at 25; NG-JDS-1-5-COL). These estimates incorporate lost and unaccounted for gas (Exh. NG-JDS-1, at 25). Based on this estimate, National Grid developed class specific marginal cost rates per Dth for Colonial Gas (Exhs. NG-JDS-1, at 25; NG-JDS-1-5-COL at 2, 3).

3. Position of the Parties

a. Attorney General

The Attorney General argues that all of National Grid's explanatory equations rely on dummy variables that do not seem to have cost-causative explanations underlying their use (Exh. AG-LS-1, at 13). The Attorney General notes that, although the use of dummy variables may be appropriate in some circumstances and may provide good statistical results, it does not provide assurance that the equation reveals the relevant effect of load (Exh. AG-LS-1, at 13). For example, the Attorney General submits that the removal of dummy variables from certain regression equations performed by National Grid causes them to lose their statistical significance (Exh. AG-LS-1, at 13-14, citing AG-17-11; AG-17-12; AG-17-16; AG-17-20; AG-17-27; AG-17-33; AG-17-37).

Further, the Attorney General argues that, although some of the dummy variables used by National Grid may be appropriate, the use of these variables to the extent employed by

National Grid without determining the underlying causes of the changes suggests that there could be problems with the underlying relationships between the variables calculated (Exh. AG-LS-1, at 14). Further, the Attorney General also takes issue with the "discontinuities" in the data series used by National Grid and contends that National Grid has failed to provide any explanation for them (Exh. AG-LS-1, at 14, citing Exh. NG-JDS-1, at 6).

The Attorney General opines that National Grid's reliance on dummy variables may stem from the use of total capacity-related plant investment (Exh. AG-LS-1, at 15). The Attorney General states that, by using total distribution plant as a dependent variable, the equations must predict replacement plant as well as plant built in response to capacity needs (Exh. AG-LS-1, at 15). According to the Attorney General, replacing plant is likely to be influenced annually by company finances and factors that are difficult to model (Exh. AG-LS-1, at 15). The Attorney General asserts that an analysis of the relationship between capital costs more directly related to peak loads might be more informative regarding the marginal cost related to load (Exh. AG-LS-1, at 15).

b. National Grid

According to National Grid, the distribution capacity-related marginal costs for both of its marginal cost studies were determined in accordance with the Department's directives and standards based on cost functions that were estimated using rigorous and well-documented statistical techniques (National Grid Brief at XI.31, citing Exh. NG-JDS-1, at 4-7, 18-19). Further, National Grid submits that it performed regression analyses in a way that thoroughly and methodically tested for the sets of explanatory variables that best explained the statistical variations in the dependent variable being estimated (Exh. NG-JDS-1, at 6). National Grid combined the results from the regression analyses with additional analyses and data that were provided by the Companies to prepare the marginal cost study (Exhs. NG-JDS-1, at 6-17; NG-JDS-1-1-BGC through NG-JDS-1-5-BGC).

4. Analysis and Findings

a. Introduction

In D.T.E. 03-40, the Department approved Boston Gas' marginal cost study but expressed its concerns about the substance of prospective studies to be performed in support of future rate cases. D.T.E. 03-40, at 376-377. In particular, the Department directed Boston Gas, in future proceedings, to provide a marginal cost study that is consistent with the directives of D.T.E. 02-24/25. D.T.E. 03-40, at 376. This includes: (1) providing an acceptable econometric analysis; (2) using multiple variable-regression equations as opposed to single variable equations; and (3) performing an analysis to check the theoretical consistency of the marginal cost model being used. D.T.E. 03-40, at 375, citing D.T.E. 02-24/25, at 243-245.[323] Further, the Department directed that, in future studies, Boston Gas must use reliable data and must estimate the marginal cost of all the expense categories and not only the marginal distribution plant cost. D.T.E. 03-40, at 377.

b. National Grid's Marginal Cost Studies

Our review of the Boston Gas-Essex Gas marginal cost study and Colonial Gas marginal cost study indicates that each study incorporates sufficient detail to allow a full

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323 The Department noted that these directives would apply to all gas and electric companies in future proceedings. D.T.E. 02-24/25, at 245.

understanding of the methods used to determine the marginal cost estimates. As an initial matter, National Grid has excluded from each marginal cost study all production, transmission, and customer costs, and instead confined each marginal cost study to the estimation of capacity-related distribution costs (Exhs. NG-JDS-1, at 7, 19; NG-JDS-1-1-BGC through NG-JDS-1-5-BGC; NG-JDS-1-1-COL through NG-JDS-1-5-COL). This methodology is consistent with Department precedent. D.T.E. 03-40, at 377.

Further, we find that National Grid used reliable data in developing each marginal cost study, as required by Department precedent. D.T.E. 03-40, at 377. While National Grid used Boston Gas data for nearly every aspect of the Boston Gas-Essex Gas marginal cost study, we find this decision to be reasonable in light of the operational integration of these entities and the availability of consistent data related to Boston Gas (Exh. NG-JDS-1, at 6).[324] Consistent with previous Department directives regarding time series, National Grid used 30 years of historical data for the Boston Gas-Essex Gas marginal cost study, encompassing the period 1979 to 2008 (Exhs. NG-JDS-1, at 7; DPU-16-22; see also, D.T.E. 02-24/25, at 243-245). Regarding Colonial Gas, National Grid used 28 years of data for the regression analyses, from 1981 to 2008 (Exh. NG-JDS-1, at 18). National Grid states that it could not locate the Colonial Gas annual reports filed with the Department for 1979 and 1980 because these reports

324 The Attorney General raises concerns about the discontinuities in the data series used by National Grid, and contends that National Grid has failed to provide any explanation for them (Exh. AG-LS-1, at 14, citing Exh. NG-JDS-1, at 6). Such discontinuities, however, are related to Essex Gas data, and not Boston Gas data (Exh. NG-JDS-1, at 6). Given that Essex Gas data was not used in the regression analyses, we find the Attorney General's concerns to be without merit.

have been misplaced as a result of the several mergers and office relocations that have occurred in the last 30 years (Exh. DPU-16-23). There is nothing in the record to suggest that the lack of two years of data would have a significant effect on the results of the regression analyses, and we note that the Attorney General does not raise an objection to the exclusion of these two years of data. As such, in this instance, we accept National Grid's inclusion of 28 years of data for the Colonial Gas regression analyses.

We note, however, that Colonial Gas's annual reports are filed with the Department and available upon request. National Grid offers no explanation for why it did not attempt to obtain this information from the Department. In future proceedings, we expect that all gas and electric local distribution companies will comply with the Department's directives and provide 30 years of full and complete information in support of their marginal cost studies.

The Department also finds that National Grid used multi-variate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions in the Boston Gas-Essex Gas marginal cost study and the Colonial Gas marginal cost study (Exhs. NG-JDS-1, at 10-11; NG-JDS-1-1-BGC through NG-JDS-1-3-BGC; NG-JDS-1-1-COL through NG-JDS-1-3-COL). Regarding Colonial Gas, National Grid submits that the materials and supplies marginal loading factor is based on a ratio of materials and supplies expenses to total utility plant, instead of regression analysis (Exh. NG-JDS-1, at 18). According to National Grid, a preliminary analysis of the data indicated significant changes in the way that materials and supply expenditures were made, especially starting in 2001 (Exhs. NG-JDS-1, at 23; DPU-16-24). Further, National Grid states that the inclusion of dummy variables was insufficient to develop a regression model that demonstrated a meaningful relationship between materials and supply expenses and utility plant (Exh. NG-JDS-1, at 23). As such, National Grid estimated the marginal loading factor for materials and supplies using the ratio of materials and supplies and utility plant for 2008 (Exh. NG-JDS-1, at 23). The record supports the significant decline in materials and supply expense, as submitted by National Grid (Exh. DPU-16-24). As such, in this instance, we accept National Grid's explanation for not conducting a regression analysis in order to estimate this expense category applicable to Colonial Gas.

The Attorney General raises concerns with the use of dummy variables in the regression analyses (Exh. AG-LS-1, at 14-15). The Department has reviewed the dummy variables used in the studies, as well as the results of the analyses performed without the inclusion of dummy variables (Exhs. NG-JDS-1-1-BGC through NG-JDS-1-3-BGC; NG-JDS-1-1-COL through NG-JDS-1-3-COL; AG-17-11; AG-17-12; AG-17-16; AG-17-20; AG-17-27; AG-17-33; AG-17-37). The Department finds that the Companies have adequately demonstrated that the use of dummy variables in performing each marginal cost study does not unreasonably alter the statistical significance of the results of the regression analyses so as to render the results unacceptable.

Finally, our review of the econometric analysis used by National Grid to calculate the marginal distribution capacity-related costs indicates that National Grid has sufficiently documented its method of estimation (Exhs. NG-JDS-1-1-BGC through NG-JDS-1-3-BGC; NG-JDS-1-1-COL through NG-JDS-1-3-COL). Additionally, we note that National Grid has applied proven econometric techniques (Exhs. NG-JDS-1-1-BGC through NG-JDS-1-3-BGC; NG-JDS-1-1-COL through NG-JDS-1-3-COL). Therefore, the Department accepts Boston Gas-Essex Gas' and Colonial Gas' marginal costs estimated from the econometric analyses.

B. Cost Allocation

National Grid performed two allocated cost of service studies ("ACOSS") as a basis to assign or allocate costs to customer rate classes (Exhs. NG-RJA-3-BGC through NG-RJA-37-BGC; NG-RJA-3-COL through NG-RJA-38-COL). The first study presents the ACOSS for the combined Boston Gas and Essex Gas, and the second study presents the ACOSS for the combined Lowell and Cape divisions of Colonial Gas (Exh. NG-RJA-1, at 3). During the proceeding, National Grid provided separate ACOSS for Boston Gas, Essex Gas, and the Lowell and Cape divisions of Colonial Gas based on updated O&M detail by account for each stand-alone company (Exhs. AG-1-102; AG-1-102 (Supp. 2); AG-2-102; AG-3-102).

National Grid used most of the same allocation factors used by Boston Gas in D.T.E. 03-40. The model used to derive these studies was not challenged or found to provide inaccurate results, and contains an internal error-checking functionality (Exh. AG-41-10).

The most important principle underlying any ACOSS is that cost incurrence should follow cost causation (Exh. NG-RJA-1, at 8). In order to establish the cost responsibility of each customer class, total operating costs are functionalized (based on characteristics of utility operation), classified (customer, capacity, or commodity related), and then allocated to customer classes using internal and external allocation factors (Exh. NG-RJA-1, at 8, 9).

National Grid argues that it has demonstrated that its ACOSS properly allocates the costs and revenues of Boston Gas and Essex Gas to customer classes, in a manner consistent with Department precedent (Exh. NG-RJA-1, at 8). No party commented on National Grid's proposed ACOSS.

The Department has evaluated National Grid's proposed ACOSS and finds that it has assigned the appropriate costs to each rate class consistent with Department precedent for cost allocation. D.T.E. 03-40, at 369; D.T.E. 01-56, at 138; D.P.U. 96-50 (Phase I) at 136. The Department directs National Grid, in its compliance filing, to re-run its ACOSS to allocate its costs and expenses as approved in this Order.

C. Rate Structure Goals

Rate structure is the level and pattern of prices charged to customers for their use of utility service. Rate structure for each rate class is a function of the cost of serving that rate class. Rate structure also considers the design of the rates so that the cost to serve a rate class is recovered in the rates charged to that class.

Utility rate structures must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.T.E. 03-40, at 365; D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; D.P.U. 96-50 (Phase I) at 133. Efficiency means that the rate structure is designed to allow a company to recover the cost of providing the service and provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling each consumer's needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the consumption of resources used to produce the utility service. D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-53.

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.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-253.

There are two steps in determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of the company's total costs to each rate class through the use of a cost of service study ("COSS"). The COSS represents the cost of serving each class at equalized rates of return given the company's level of total costs. D.T.E. 03-40, at 367; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29; D.P.U. 96-50 (Phase I) at 135.

There are four steps to developing a COSS. The first step is to classify costs by category, according to the service function they provide -- either (1) production and storage or (2) transmission and distribution. The second step is to classify expenses in each functional category according to the factors underlying their causation (i.e., demand, energy, or customer-related). The third step is to identify the most appropriate allocator for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total costs of serving each rate class. D.T.E. 03-40, at 366-367; D.T.E. 01-56, at 136; D.T.E. 98-51, at 131-132; D.P.U. 96-50 (Phase I) at 135.

The results of the COSS are compared normalized test year revenues. If these amounts are close, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are significantly high, 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 them in a single step. See D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs to serve, 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. The Department has ordered the establishment of special subsidized rate classes for certain low-income customers. In moving toward our goal of efficiency, the Department also considers the effect of such rates on low-income customers. D.T.E. 03-40, at 367; D.T.E. 01-56, at 137; D.T.E. 01-50, at 29-30.

In order 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 unless a clear record exists to support such subsidies – or they are required by statute, e.g., G.L. c. 164, § 1F(4)(I). The Department reaffirms its rate structure goals that result in rates that are fair and cost-based and enable customers to adjust to changes. D.T.E. 03-40, at 368; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

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 rate design for a given rate class is constrained by the requirement that it produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.T.E. 03-40, at 368; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

D. National Grid's Proposal

1. Introduction

National Grid proposes to consolidate Boston Gas' and Essex Gas' residential rate structures (Exh. NG-JDS-2, at 3). National Grid claims that Boston Gas' and Essex Gas' residential rate classifications are identical and, therefore, there is no need to make any changes to the residential rate classifications to allow for their consolidation (Exh. NG-JDS-2, at 8). However, National Grid does not propose at this time to consolidate Boston Gas' and Essex Gas' C&I rate structures because of operational and customer issues that would be created by such consolidation (Exh. NG-JDS-2, at 3). For example, Boston Gas' C&I customers are classified according to the capacity of the meter that is used to measure the customer's usage, whereas Essex Gas' customers are classified according to their annual use (Exh. NG-JDS-2, at 7). National Grid concludes that, because of the significant difference in the method of classifying customers, consolidating the rates would likely cause large bill impacts for many customers. Finally, National Grid proposes to consolidate the residential and C&I rate structures for Colonial Gas-Lowell and Colonial Gas-Cape (Exh. NG-JDS-2, at 3).

National Grid states that class revenue targets for both Boston Gas-Essex Gas and Colonial Gas are determined based on the results of the allocated cost of service study ("ACOSS") (Exh. NG-JDS-2, at 20, 37). The ACOSS determined the fully allocated costs at equalized rates of return to serve for each National Grid rate class (Exh. NG-JDS-2, at 20, 37). According to National Grid, the fully-allocated total base revenue requirement is net of the costs recovered through the GAF and LDAF (Exh. NG-JDS-2, at 20, 37).

National Grid designed its base rates to recover $449,054,677 total base distribution revenue requirement for Boston Gas-Essex Gas and $106,002,705 for Colonial Gas (Exh. NG-JDS-2, at 19, 37). National Grid undertook the following steps to determine class-specific revenue targets for Boston Gas-Essex Gas and Colonial Gas that it then used to design base rates. First, National Grid calculated current total class revenues by taking the product of pro forma normalized billing determinants and current distribution, GAF, and LDAF rates (Exh. NG-JDS-2, at 20-21, 38-39). Second, National Grid used, as the initial basis for setting class revenue targets, the class-specific revenue requirement determined in the ACOSS (Exh. NG-JDS-2, at 20, 37). Third, National Grid calculated class revenue increase impacts by comparing each rate class' current revenues to its proposed revenues and set a class revenue increase cap at 110 percent of the overall rate increase so as to limit the amount of the increase assigned to any class, and thus to satisfy rate continuity (Exh. NG-JDS-2, at 21, 38). Fourth, National Grid assigned any revenue shortfalls that result from the class revenue increase cap, to all classes by calculating the difference between the capped percent increase and the total potential percent increase for each class, weighted by the total pro forma class revenues (Exh. NG-JDS-2, at 24, 42). As the final step, National Grid determined the base revenue target increase for each class by subtracting the LDAF and GAF revenue increase from the total class revenue increase (Exh. NG-JDS-2, at 25, 42). National Grid added the base revenue target increase for each class to the pro forma test year base revenues to determine total class revenue targets (Exh. NG-JDS-2, at 25, 43).

National Grid undertook the following steps to design its base rates to recover the target revenue for each rate class. First, National Grid determined the level of the customer charges (Exh. NG-JDS-2, at 25, 43). To determine the level of customer charges for each class, National Grid states that it considered: (1) the current Boston Gas level of its customer charges; (2) the embedded customer costs that were calculated in the ACOSS; (3) a survey of other Massachusetts gas distribution companies' customer charges; (4) the Department's rate continuity goal; (6) customer bill impacts; and (7) the Department's directives concerning customer charges in recent rate cases such as D.P.U. 09-30 and D.P.U. 09-39 (Exh. NG-JDS-2, at 26, 43-44).

Based on the results of the ACOSS for Boston Gas-Essex Gas, no rate class is currently collecting its full embedded customer cost through its customer charge except for Essex Gas' rate G/T-52 (Exh. NG-JDS-2, at 27). According to National Grid, Boston Gas' customer charges are generally consistent with other Massachusetts gas distribution companies excluding National Grid's other gas companies (Exh. NG-JDS-2, at 28). However, National Grid states that current customer charges for Essex Gas customers are the lowest in Massachusetts, excluding Colonial Gas customers (Exh. NG-JDS-2, at 28). In addition, National Grid states that customer charges for classes G-41, G-42 and G-43 are not consistent with the unit costs and with customer charges of other utilities (Exh. NG-JDS-2, at 27-29).

Likewise, based on the results of the ACOSS for Colonial Gas-Lowell and Colonial Gas-Cape, National Grid states that no rate class is currently collecting its full embedded customer cost through its customer charge, especially for Colonial Gas' C&I customer charges, which are significantly below cost-based levels (Exh. NG-JDS-2, at 44-45). Therefore, based on these considerations, National Grid proposes to set the customer charges for both Boston Gas-Essex Gas and Colonial Gas equal to the current customer charges for Boston Gas (Exh. NG-JDS-2, at 29-30). National Grid calculated class customer charge revenues by multiplying the proposed customer charges by the test year class customer counts (Exh. NG-JDS-2, at 30, 47).

Second, National Grid determined the amount of the class target revenues to be recovered through peak period rates and the amount to be recovered through off-peak period rates (Exh. NG-JDS-2, at 26, 43). The Companies state that they established the overall level of base rates by season in a manner that would promote efficiency in pricing, that would be understandable by customers, and that would not produce undue customer bill impacts (Exh. NG-JDS-2, at 31, 48).

Third, National Grid determined the appropriate size of the head blocks and the rate differential between head block and tail blocks variable energy charges (Exh. NG-JDS-2, at 26, 43). For each rate class by season, the Companies selected based on their professional judgment, the therm head block size at which approximately 25 percent of total class seasonal therms would fall in the head block (Exh. NG-JDS-2, at 31, 48). In setting the head block size the Companies also tried to ensure that the percentage of bills with usage ending in the head block was reasonably close to 25 percent (Exh. NG-JDS-2, at 31, 48).

The Companies state that they set inclining block rates because they were directed to do so by the Department in D.P.U. 09-30 and D.P.U. 08-35. Based on their professional judgment, the Companies set the tail block rates for each season at 105 percent of the average variable rates for that season and the head block rates were then calculated to recover the remaining target revenues to be collected through the variable energy charges (Exh. NG-JDS-2, at 31, 48). In addition, National Grid determined the low-income discounted rates and calculated the revenue shortfall resulting from the low-income discount, which would be recovered through the residential assistance adjustment factor ("RAAF") (Exh. NG-JDS-2, at 26, 32, 43, 49).

National Grid is concerned that setting the residential non-discounted rates at the same charges as the corresponding discounted rates, which will receive a 25 percent discount off of the total bill, will cause significant bill implications for the non-discounted rates (Exh. LI-1). To address this concern, National Grid proposed an alternative rate design for the discounted rates R-2 and R-4 (Exh. LI-1). The alternative rate design set the rates R-2 and R-4 customer charges for Boston Gas-Essex Gas at $7.16, and set the rates R-2 and R-4 customer charges for Colonial at $5.71 and $4.70, respectively, rather than setting them all at the current Boston Gas customer charges (Exh. LI-1). The other charges were determined using the method described above.

2. Positions of the Parties

a. Attorney General

The Attorney General raises a number of arguments with respect to the proposed rate consolidation and its proposed rate design. First, the Attorney General argues that the Department should reject National Grid's proposed rate consolidation because National Grid has failed to provide evidence necessary for the approval of such proposal. More specifically, the Attorney General contends that the Companies must present evidence concerning the costs of consolidation so that the impact of the consolidation upon customers can be considered in the determination of just and reasonable rates (Attorney General Brief at 188). According to the Attorney General, National Grid must disclose the method used to consolidate the revenue requirement so that the Department can review the isolated impact of the consolidations (Attorney General Brief at 188). The Attorney General posits that, without such evidence, there is no way to determine whether the consolidation is arbitrary or unreasonable (Attorney General Brief at 188).

Further, the Attorney General argues that Department precedent requires that the Companies submit a plan of consolidation that will equalize the rates for the various divisions in addition to submitting evidence concerning the costs of the consolidation so that the impact of the consolidation upon customers can be considered in the determination of just and reasonable rates (Attorney General Brief at 187-188, citing, Boston Gas Company, D.P.U. 18264, at 23-24 (1975)). Moreover, the Attorney General contends that Essex Gas and Colonial Gas were expressly directed to submit, prior to the end of Boston Gas' PBR plan, a "proposal" as part of any Essex Gas or Colonial Gas rate case to ensure the elimination of any potential for cross-subsidization that may exist among the rates of Essex Gas or Colonial Gas (Attorney General Brief at 188, citing Boston Gas Company, D.T.E. 03-40, at 224). According to the Attorney General, National Grid failed to provide any evidence regarding cross subsidization in the initial filing and ultimately provided it only upon request of the Attorney General in this proceeding (Attorney General Brief at 190).

The Attorney General asserts that, based on the evidence presented, customers of Essex Gas and Colonial Gas-Cape will be harmed by paying more than what it costs to serve them (Attorney General Brief at 190). For example, the Attorney General contends that Essex Gas residential heating customers will pay approximately $3.2 million more than the separate cost of serving them, while Essex Gas customers as a whole will pay $5.2 million more than their separate cost of service (Attorney General Reply Brief at 77). Likewise, the Attorney General claims that Colonial Gas-Cape's residential heating customers will pay $2.1 million more than the separate cost of serving them, while the Colonial Gas-Cape as a whole will pay $4.7 million more that its separate cost of service (Attorney General Reply Brief at 77).

In addition, the Attorney General argues that National Grid has failed to demonstrate any significant savings or increased efficiencies resulting from the proposed consolidation (Attorney General Brief at 191). Specifically, the Attorney General claims that while administrative and general expenses may be very similar for Boston Gas, Essex Gas, Colonial Gas-Lowell, and Colonial Gas-Cape, their respective O&M expenses are different (Attorney General Brief at 192). As such, the Attorney General disputes National Grid's position that consolidation will eliminate inefficiencies and provide cost savings (Attorney General Brief at 192). In addition, the Attorney General claims that National Grid has failed to quantify any significant efficiencies, other than $222,219 related to expenses that the Companies claim could be reduced by the consolidation (Attorney General Reply Brief at 75).

The Attorney General also argues that the proposed move to consolidated rates produces large increases in customer charges that contravene Department rate design principles (Attorney General Brief at 193). According to the Attorney General, the customer charge increases are large and unnecessary and have been designed in part simply to allow the consolidation of rates (Attorney General Brief at 193). Specifically, National Grid claims that, for Essex Gas, the adoption of Boston Gas' customer charges will result in increases in customer charges ranging from 44 percent to well over 4,000 percent, except for rate class G-52 where the proposed charge is 81 percent less than the current charge (Attorney General Brief at 195). Further, the Attorney General asserts that for Colonial Gas-Cape, the increases will range between 6.0 percent to over 1,000 percent and for Colonial Gas–Lowell, the increases will range between 95 percent to close to 5,000 percent (Attorney General Brief at 195, citing Exh. AG-DED-1, Sch. DED-11). The Attorney General argues that National Grid has failed to prove how increases of these magnitudes do not contravene cardinal rate design objectives such as rate continuity (Attorney General Brief at 195).

Further, the Attorney General argues that revenue decoupling mechanisms remove the need to introduce dramatically higher customer charges to create revenue stability (Attorney General Brief at 197). The Attorney General claims that other state utility regulatory commissions, such as those in Utah and Washington, as well as the Regulatory Assistance Project[325] have rejected increases in customer charges as either inconsistent with revenue decoupling mechanisms or contravening energy efficient goals (Attorney General Brief at 197-198). In addition, the Attorney General disagrees with the premise, as argued by National Grid, that the increase in the customer charge is not relevant because only the increase to total bill is relevant (Attorney General Reply Brief at 78). According to the Attorney General, this argument ignores the fact that the increase to the customer charge has a significant impact on interclass bill impacts (Attorney General Reply Brief at 78). Finally, the Attorney General argues that the Companies' justification for designing rates that are similar to other Massachusetts local gas distribution companies is not a compelling reason for of National Grid's proposed rate design (Attorney General Reply Brief at 79). In conclusion, the Attorney General argues that the large increases in customer charges proposed by National Grid are contrary to the principles of rate continuity and are only the result of National Grid's desire to eventually consolidate all rates (Attorney General Brief at 198).

Turning to the issue of National Grid's proposed inclining block rate structure, the Attorney General argues this rate structure results in several negative outcomes (Attorney General Brief at 198). For example, the Attorney General argues that the

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325 The Regulatory Assistance project is a global, non-profit team of experts that focuses on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to government officials on a broad range of energy and environmental issues (http://www.raponline.org/AboutRAP.asp).

rate design violates the Department's ratemaking principles because it can lead to rate volatility, it is not cost based, it discriminates between low-use and high-use customers both between and within customer classes, and it undermines overall energy efficiency goals (Attorney General Brief at 199-200). In addition, the Attorney General posits that the proposed inclining block rate structure makes reduced gas consumption uncertain, as it would fundamentally lead to inefficient use of resources, both in terms of the use of gas and of the possible substitution of other energy sources for gas (Attorney General Reply Brief at 80).

Accordingly, for the reasons explained above, the Attorney General argues that National Grid's proposal to consolidate rates should be rejected by the Department (Attorney General Brief at 206). Instead, the Attorney General asserts that the Companies should continue to provide separate rates for Boston Gas, Essex Gas, Colonial Gas-Lowell and Colonial Gas-Cape based on each entity's costs and revenue requirements (Attorney General Brief at 205). Further, the Attorney General argues that the residential customer charges should be increased by a percentage that is capped relative to the class increase percentage (Attorney General Brief at 206). In addition, the Attorney General asserts that seasonal volumetric charges should change from the current declining block rates structure to a flat rate structure to provide energy efficiency pricing signals and to mitigate adverse bill impacts (Attorney General Brief at 206-207).

b. Low Income Intervenors

The Low Income Intervenors contend that National Grid's proposed disconnected rate design alternative should be rejected because it is likely to be misunderstood by the affected low-income customers (Low Income Intervenors Brief at 7).[326] Specifically, the Low Income Intervenors submit that a customer that compares the R-2 and R-4 low-income rates to the R-1 and R-3 non-discounted rates would find that the 25 percent discount had not in fact been applied to the non-low-income, non-heating and heating rates (Low Income Intervenors Brief at 7). In support of this argument, the Low Income Intervenors provide multiple hypothetical bill impact scenarios for residential heating and non-heating customers (Low Income Intervenors Brief, Appendix A).[327] According to the Low Income Intervenors, the results of this analysis demonstrate that, in general, the very high percentage bill increases fall primarily on lower-usage customers with the customer charge proposed by National

[326] National Grid proposed an alternate rate design for low-income rates R-2 and R-4 which set the customer charges for these rates lower than the R-1 and R-3 customer charges, respectively, and then collected the remaining class revenue requirement through the delivery charges such that the total amount of revenue collected would be revenue neutral to setting the R-2 and R-4 rates and the same charges as R-1 and R-3, respectively. This alternate rate design proposal is referred to as the "disconnected" rate design (Exh. LI-1-3).

[327] These bill impact scenarios use a 25 percent discount off of the total bill assuming hypothetical revenue increases at 100, 50, and 25 percent, mixed with customer charges as proposed by National Grid, as well as a customer charge of $4.00 as advocated by the Low Income Intervenors (Low Income Intervenors Brief, Appendix A). The Low Income Intervenors then analyzed bill impacts for various usage levels for R1/R2 and R3/R4 customers using a combination of several scenarios (Low Income Intervenors Brief, Appendix A).

Grid (Low Income Intervenors Brief at 7). The Low Income Intervenors claim, however, that the application of a $4.00 customer charge reduces the number of customers overall that would receive high bill impacts, in particular among lower-usage customers (Low Income Intervenors Brief at 7). Thus, the Low Income Intervenors urge the Department to consider adjustments to customer charges that can assist in keeping rate increases within acceptable bounds, while still maintaining the proposed low-income discount rate design and other rate design objectives of the Department (Low Income Intervenors Reply Brief at 7)

c. National Grid

National Grid argues that it has presented a reasonable consolidation plan that is supported by the record in this case (National Grid Brief at XI.7). According to National Grid, it was not required to submit a plan to equalize the base rates for Boston Gas, Essex Gas, and Colonial Gas in advance of seeking to consolidate rates in this base rate proceeding (National Grid Brief at XI.7). Rather, in the instant filing, National Grid claims it was required to take steps to eliminate the rate differentials among similar situated classes of customers (National Grid Brief at XI.7-8, citing Boston Gas Company, D.P.U. 18264, at 23-24). In this regard, National Grid asserts that it has provided a detailed and well-conceived plan for its rate consolidation proposals (National Grid Brief at XI.8). More specifically, National Grid argues that it provided an extensive description and explanation of the consolidation plan, an analysis supporting its proposed combined rate classifications for Colonial Gas' C&I customers, rate design models which demonstrated in a clear and well-documented manner how the consolidated rates were calculated, bill impact analyses, and detailed information on the effect of National Grid's rate consolidation plans on customers (National Grid Brief at XI.8, citing Exhs. NG-JDS-2; NG-JDS-2-3-BGC, NG-JDS-2-4-BGC, 2-5-BGC; NG-JDS-NG-JDS-2-1, NG-JDS-2-2, NG-JDS-2-4, NG-JDS-2-6, NG-JDS-2-7, NG-JDS-2-8).

National Grid argues that its rate consolidation proposal is consistent with the fact that its Massachusetts gas distribution operations are managed on a fully integrated basis, including O&M activities, infrastructure replacement and enhancement projects, gas supply planning, and procurement and administrative and general functions (National Grid Brief at XI.14). Thus, National Grid reasons, by maintaining separate rate classifications and separate tariffs for Colonial Gas-Cape and Colonial Gas-Lowell, and for Boston Gas and Essex Gas residential customers, National Grid experiences administrative and customer service inefficiencies (National Grid Brief at XI.15, citing Exh. AG-16-28). Further, National Grid claims that its consolidation proposal is a continuation of a rate consolidation process that includes prior consolidations of the LDAF and GAF of Boston Gas and Colonial Gas, which began in 2004 (National Grid Brief at XI.15).

In addition, National Grid claims that, based on test year revenues, approximately 59 percent of the Companies' rates are already determined on a consolidated basis (National Grid Brief at XI.15). With respect to base rates, National

Grid argues that its consolidation proposal is a continuation of a rate consolidation process that began in 1975, when the Department ordered the consolidation of the separate rates of the western, northern, and Boston divisions of Boston Gas (National Grid Brief at XI.15, citing, Boston Gas Company, D.P.U. 18264, at 23-24, RR-AG-64).

National Grid rejects the notion that customers of Essex Gas and Colonial Gas-Cape will pay more than the cost of serving them (National Grid Brief at XI.12). Specifically, National Grid argues that the results of individual ACOSS, which concern costs and not rates, have no direct bearing on the rates or revenues proposed in this proceeding (National Grid Brief at XI.13). Rather, National Grid asserts that an analysis of rates based on the proposed rate consolidation plans reveals the more accurate result of rate consolidation, than a comparison of rates based on the separate revenue requirements, separate ACOSS, and separate rate designs (National Grid Brief at XI.13). Specifically, National Grid claims that this comparison demonstrates that: (1) almost every rate design will result in revenues at proposed rates for some classes that are less than the class revenue requirement at equal rates of return, as determined by the ACOSS, as well as revenues to the remaining classes that are greater than the class revenue requirement at equal rates of return; and (2) rate subsidization between classes in Massachusetts is generally caused by the low-income discounted rates and limits on rate increases for any class for rate continuity considerations (National Grid Brief at XI.14, citing Exh. DPU-21-3). In addition, National Grid argues that the level of inter-class subsidization created by consolidation of Boston Gas' and Essex Gas' residential rates and the consolidation of all of Colonial Gas' rates is similar to the level of between-class subsidization that is the result of caps on increases in rates by class for rate continuity considerations, as well as low-income rate discounts (National Grid Brief at XI.14). Therefore, based on this analysis, National Grid asserts that its proposal to consolidate rates does not result in unacceptable cross-subsidization outcomes (National Grid Brief at XI.14).

Regarding rate design, National Grid argues that its proposed rate design follows Department precedent and ratemaking principles, and is consistent with the Department's long standing rate design goals (National Grid Brief at XI.17, citing D.P.U. 09-30, at 373; Exh. NG-JDS-2, at 17). In addition, National Grid contends that the proposed base rates have been designed to conform to the following rate making principles: efficiency, simplicity, continuity of rates, and fairness between rate classes (National Grid Brief at XI.17). Specifically, National Grid maintains that to set the base revenue targets for each class, National Grid considered: (1) the results of the fully allocated costs at equalized rates of return for each rate class as determined in the ACOSS; (2) the overall impact of all changes in revenues on each class as a whole, including the changes in costs to be recovered through the GAF and LDAF and; (3) customer charges that are better aligned with those of other gas companies in Massachusetts (National Grid Brief at XI.17, citing Exh. NG-JDS-2, at 17). Further, National Grid claims that the inclining rate structure, including the size of the proposed head blocks as well as the calculation of the tail block rates, has been designed in accordance with Department precedent (National Grid Brief at XI.18, citing NG-JDS-2, at 31, 48; D.P.U. 09-39; D.P.U. 09-30; D.P.U. 08-35).

Next, according to National Grid, its proposal to increase the customer charges for Essex Gas and Colonial Gas to the level of current Boston Gas customer charges will: (1) reduce Essex Gas and Colonial Gas intra-class rate inequities, where low-use customers in each class are subsidized by high-use customers in that class; (2) allow for partial alignment of National Grid rates across the entire Massachusetts service territory, which will simplify future rate consolidation; and (3) make Essex Gas and Colonial Gas customer charges more consistent with other gas companies in Massachusetts (National Grid Brief at XI.21, citing Exhs. NG-JDS-2, at 27-28, 45-46; NG-JDS-2, at 29, Table 4). National Grid disputes the Attorney General's assertion that the Companies' ratepayers are already paying customer charges that are higher than 65 percent of other comparable northeastern gas utilities, and well in excess of other major gas distribution companies even before the new proposals are taken into account (National Grid Brief at XI.23). Further, National Grid disputes the Attorney General's assertion that rate consolidation will result in extreme percentage increases in customer charges. Instead, National Grid argues that customer charges for Essex Gas and Colonial Gas are generally the lowest in Massachusetts and are well below the unit cost of customer related costs (National Grid Brief at XI.23-24; National Grid Reply Brief at 128). Finally, National Grid submits that significant overall rate volatility would result if the Attorney General's recommendation of lower customer charges were coupled with the Companies' proposed inclining block rate structure (National Grid Brief at XI.26).

Finally, National Grid takes issue with the Low Income Intervenors' position on rate design (National Grid Brief at XI.27-31). National Grid claims that the Low Income Intervenors' rate design recommendation is confusing, unworkable, and without support in the record (National Grid Brief at XI.30-31). In particular, National Grid argues that little weight should be given to the Low Income Intervenors' arguments concerning the proposed disconnected rates (National Grid Brief at XI.27-28). Rather, National Grid submits that if the Department chooses to make rate design modifications to address disparities in low-income bill impacts that have been identified and examined in the low-income dockets, the redesigned non-discounted rates should be "disconnected" from the actual R-1 and R-3 rates that are charged to R-1 and R-3 customers (National Grid Brief at XI.26-27). National Grid states that disconnected R-1 and R-3 rates could be designed to address bill impact disparities that are unique to the R-2 and R-4 customers, without compromising the Department's rate design objectives and standards for the non-discounted R-1 and R-3 rates (National Grid Brief at XI.27). Further, National Grid contends that the Low Income Intervenors' brief should be given no weight in this proceeding, as it contains extensive original analysis and expert testimony in the guise of a brief and neither National Grid nor any other parties have been given the opportunity to conduct cross examination of any witnesses on behalf of the Low Income Intervenors (National Grid Brief at XI.29-30).

3. Analysis and Findings

a. Rate Consolidation

A utility's rate structure comprises the level and pattern of prices charged to specific customers for the use of utility services. The specific rate structure of each rate class is a function of the cost to the utility of providing service to the rate class and of the design of rates calculated to recover the cost. Rate classes are established based on the costs of serving different groups of customers. Boston Edison Company, D.P.U. 84-236-A, at 11 (1986). The costs of serving different rate classes are primarily a function of the difference in their load characteristics. D.P.U. 1720, at 137-142.

To determine if the proposed rate consolidation should be allowed, we must consider whether it is consistent with our rate design goals of simplicity, efficiency, continuity, fairness, and earnings stability. Further, we will examine bill impacts at the rate class level to determine if our continuity goal is met. Finally, to ensure our goals of efficiency, fairness, and earnings stability are not violated we will examine if the classes that are proposed to be consolidated have similar load characteristics.

Consolidating rates will simplify National Grid's rate structure and, therefore, we find that it meets our simplicity goal. The proposed consolidation of rates across the Companies' service areas can be seen as the continuation of a long and progressive effort by National Grid to eventually consolidate the rates of all of its Massachusetts gas operations into a single set of rates. National Grid's reorganization efforts started in this direction with the consolidation of Boston Gas', Essex Gas', and Colonial Gas' LDAF and CGA clauses, as well as the consolidation of their Terms and Conditions. National Grid, D.T.E. 04-62, at 47-48 (2004). As such, consolidation of the Companies' tariffs represents a logical continuation of its reorganization efforts and would increase both administrative efficiency and customer understanding of the Companies' rate structure.

These benefits are not primarily associated with monetary savings. However, we disagree with the Attorney General's assertion that the Companies must demonstrate savings in order to justify the reasonableness of the proposed rate consolidation. See New England Gas Company, D.P.U. 08-35, at 246-248; Massachusetts-American Water Company, D.P.U. 95-118, at 173 (1996); Commonwealth Gas Company, D.P.U. 1120, at 83-84 (1982). Instead, as discussed above, when determining whether a proposed rate consolidation is appropriate, the Department considers the extent to which the proposed rate classes have similar load characteristics and produce bill impacts that do not violate our rate continuity goal.

Based on these considerations, the Department has reviewed the different load characteristics and rate classifications of National Grid's proposed rate classes. In the case of Boston Gas and Essex Gas, the residential rate classifications are identical and thus the load characteristics of their respective residential rate classes are similar (Exh.

NG-AEL-5, at 213-217, and 234-239). By contrast, for Colonial Gas-Cape and Colonial Gas-Lowell, the residential rate classifications are identical but the current C&I rate classifications are classified using different annual usage (Exh. NG-AEL-5, at 250-283). Therefore, because of these marked differences among C&I customers, it was necessary for National Grid to establish new rate class definitions that would result in groupings of customers that were most similar to each other within each rate class group and most different between rate class groups (Exh. NG-JDS-2-7, at 5-49). Based on our review of this analysis, we conclude that National Grid used an appropriate method to establish a common set of rate classes for Boston Gas and Essex Gas as well as for Colonial Gas-Lowell and Colonial Gas-Cape.

In addition, the Department has examined the class bill impacts resulting from the proposed rate increase assuming consolidation as well as the class bill impacts that would result in the event that the proposed consolidation is disallowed (Exh. DPU-21-3, Atts. (a-b)). Under both scenarios, the revenue requirement assigned to each rate class was capped with the use of the 110 percent rate cap of the overall rate increase (Exh. DPU-21-3, Atts. (a-b); Tr. 12, at 1641). We find that the class bill impacts created by the consolidation of Boston Gas' and Essex Gas' residential rates and the consolidation of all of Colonial Gas' rates satisfy our rate continuity goal and are similar to the class bill impacts of maintaining rates on a stand-alone basis. Therefore, we find the bill impacts resulting from the consolidation to be reasonable and consistent with our goals of rate continuity and simplicity.

For the reasons discussed above, we accept the Companies' proposed consolidation of rates. Issues with respect to the design of the consolidated rates will be discussed below.

b. Allocation of Rates

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 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. This allocation method satisfies the Department's rate structure goal of fairness. However, the Department must balance its goal of fairness with its goal of rate continuity.

We have reviewed the changes in National Grid's total revenue requirements by rate class and the annual and seasonal bill impacts by consumption level within rate classes. Based upon our review, we accept National Grid's proposal that to address the goal of rate continuity, no rate class shall receive an increase to its total revenues (inclusive of LDAF and CGAF revenues) greater than 110 percent of the overall rate increase (Exh. NG-JDS-2, at 23, 41). The Department finds that the 110 percent cap is an appropriate cap that meets our rate structure goals of fairness and continuity by ensuring that the final rates of each rate class represent or approach the cost to serve the class, that the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies, and the magnitude of change to any one class is contained within reasonable bounds.

As illustrated on Schedule 11, the remaining revenue increase (i.e., the amount above the 110 percent cap) shall be allocated by calculating the difference between the capped percent increase and the total potential percent increase for each class, weighted by the total pro forma class revenues. The rate design of customer charges and volumetric rates for each residential and commercial rate class will be discussed below.

c. Inclining Block Rate Structure

Regarding the design of the delivery charges, the Department has stated that: "the design of distribution rates should be aligned with important state, regional, and national goals to promote the most efficient use of society's resources and to lower customers' bills through increased end-use efficiency. To best meet these goals, rates should have an inclining block rate structure and any resulting loss in revenues from declining sales should be recovered through the decoupling mechanism as discussed in D.P.U. 07-50-A." D.P.U. 08-35, at 249.

The Attorney General argues that inclining block rates: (1) will lead to rate volatility; (2) are not cost based; (3) discriminate against high use customers; and (4) undermine energy efficiency by providing uneconomic price signals. However, the arguments raised by the Attorney General in this proceeding were fully considered in the Department's determination in D.P.U. 08-35 to adopt inclining block rates.

The Department finds that National Grid's proposed inclining block rate structure is consistent with the Department's directives in D.P.U. 07-50-A, D.P.U. 08-35, and D.P.U. 09-30. Further, we find that National Grid's proposal to: (1) set the head block sizes for each rate class and for each season at a level where 25 percent of total class seasonal billed sales fall in the head block; (2) to then set the tail block rates for each season at 105 percent of the average variable rates for that season; and (3) to set the head block rates at a level that would recover the remaining target revenues to be collected through the variable energy charges for that season is consistent with our goal to promote increased end-use efficiency. Therefore, we approve the Companies' proposed method for establishing the size of the head blocks, and the tail block and head block rates.

d. Customer and Delivery Charges

To determine the appropriate customer charges the Department must balance the competing goals of: (1) aligning National Grid's gas rates across Massachusetts; (2) lowering customers bills through increased end-use efficiency; and (3) rate continuity. We find that National Grid's proposal to set customer charges at the current Boston Gas customer charge for the corresponding customer class does not provide the appropriate balance of these goals.

Alternately, in view of our goals stated above, we find that it is appropriate to set the Boston Gas and Essex Gas customer charge for each rate class at the same rate for the corresponding rate class. In addition, with the exception of the revenue requirement for the R-3 rate classes for Boston Gas-Essex Gas, the Department finds that the method for allocation of the base revenue requirement as shown in exhibits NG-JDS-2-3-BGC at 31-33, line 98; and NG-JDS-2-6-COL at 43-44, line 245, provides an appropriate balance of our rate design goals and, therefore, is approved. Regarding the revenue requirement for rate class R-3 for Boston Gas-Essex Gas, we determine that for rate continuity reasons, it is appropriate to set the allocation factor at 2.0.

Regarding the proper level to set the customer charge and delivery charges for each rate class in each season, the Department will make this determination on a rate class-by-rate class basis based on our rate design goals and the methods for calculating rates approved above. The rate-by-rate analysis is discussed below.

E. Boston Gas-Essex Gas Residential Rate-by-Rate Analysis - Rates R-1, R-2, R-3 and R-4 (Residential Non-Heating and Heating)

1. Introduction

Rate R-1 is available to all residential customers who do not have gas space-heating equipment, while rate R-3 is available to all residential customers who have gas space-heating equipment. Both R-1 and R-3 require that a customer take service through one meter in a single building that contains no more than four dwelling units (Exh. NG-AEL-5 at 213, 215). National Grid's current and proposed rates R-1 and R-3 distribution charges for Boston Gas and Essex Gas are as shown in the following table.

	Current				Proposed	
Rate R-1	Boston Gas		Essex Gas		Boston-Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	10.98	10.98	7.60	7.60	10.98	10.98
Head Block Size (Therms)	20	10	20	20	10	5
Head Block Rate ($/Therm)	0.6228	0.06228	0.9620	0.7248	0.5246	0.4687
Tail Block Rate ($/Therm)	0.1473	0.1473	0.5840	0.4168	0.5963	0.5421
Rate R-3						
Customer Charge ($)	13.89	13.89	7.84	7.84	13.89	13.89
Head Block Size (Therms)	150	30	100	30	40	10
Head Block Rate ($/Therm)	0.3994	0.3994	0.4901	0.3401	0.3859	0.3038
Tail Block Rate ($/Therm)	0.2217	0.2217	0.2864	0.1401	0.4653	0.3579

Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 213 and 215.

Rate R-2 is a subsidized rate that is available at single locations to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Exh. NG-AEL-5, at 214). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See D.P.U. 08-104.

Rate R-4 is a subsidized rate that is available at single locations to residential customers for domestic heating purposes in private dwellings and individual apartments (Exh. NG-AEL-5, at 214). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See D.P.U. 08-104, at 2-3.

The Department has approved for Boston Gas-Essex Gas a low-income discount rate of 25 percent applied to the total bill. Low-Income Discount Rate, D.P.U. 10-41 through D.P.U. 10-48, at 18 (2010). In addition, the Department has approved the Companies' proposal for Boston Gas-Essex Gas distribution rates that become effective November 2, 2010, to have the R-1 charges be the same as the R-2 charges, and the R-3 charges be the same as the R-4 charges. D.P.U. 10-41 through D.P.U. 10-48, at 4-5, 18. National Grid's current and proposed rates R-2 and R-4 distribution charges for Boston Gas and Essex Gas are as shown in the following table.

	Current				Proposed	
Rate R-2	Boston Gas		Essex Gas		Boston-Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	4.71	4.71	4.85	4.85	10.98	10.98
Head Block Size (Therms)	20	10	20	20	10	5
Head Block Rate ($/Therm)	0.2692	0.2692	0.6133	0.4621	0.5246	0.4687
Tail Block Rate ($/Therm)	0.0661	0.0661	0.3726	0.2657	0.5963	0.5421
Rate R-4						
Customer Charge ($)	5.33	5.33	2.78	2.78	13.89	13.89
Head Block Size (Therms)	150	30	100	30	40	10
Head Block Rate ($/Therm)	0.1540	0.154	0.1737	0.1205	0.3859	0.3038
Tail Block Rate ($/Therm)	0.0858	0.0858	0.1006	0.0496	0.4653	0.3579
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 214 and 216.						

2. Analysis and Findings

The current customer charges for the residential non-heating rate classes that are being consolidated range from a high of $10.98 per month to a low of $4.71 per month. The current customer charges for the residential heating classes that are being consolidated range from a high of $13.89 per month to a low of $2.78 per month. According to the Boston Gas-Essex Gas ACOSS, the embedded customer charges for rates R-1 and R-3 are $15.50 and $26.37 per month for Boston Gas and $24.12 and $41.20 per month for Essex Gas, respectively.

The Department has the difficult task of establishing a customer charge that satisfies our rate continuity and efficiency rate design goals where there are large variances in current customer charges and, at the same time, achieves our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers' bills through increased end-use efficiency.

Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that (1) R-1 and R-2 rates, designed with an $8.00 monthly customer charge, and (2) R-3 and R-4 rates, designed with a $10.00 monthly customer charge best meet our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above[328] (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail

[328] The calculation of all volumetric delivery charges shall be truncated after the fourth decimal place.

block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

F. Boston Gas Commercial and Industrial Rate-by-Rate Analysis

1. Rate G-41B (C&I Low Use, Low Load Factor

The G-41B rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 218). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $28.97 (Exh. NG-AEL-5, at 218). National Grid's current and proposed rate G-41B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-41B	Boston Gas		Boston-Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	28.97	28.97	28.97	28.97
Head Block Size (Therms)	N/A	N/A	60	15
Head Block Rate ($/Therm)	0.3724	0.2577	0.3662	0.2339
Tail Block Rate ($/Therm)	0.3724	0.2577	0.4509	0.2909
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 218.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-41B is $33.99 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas' rate G-41 is $6.83. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-41B designed with a $21.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

2. Rate G-42B (C&I Medium Use, Low Load Factor

The G-42B rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 220). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $52.14 (Exh. NG-AEL-5, at 220). National Grid's current and proposed rate G-42B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-42B	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	52.14	52.14	52.14	52.14
Head Block Size (Therms)	N/A	N/A	250	70
Head Block Rate ($/Thern	0.2681	0.2323	0.3173	0.2081
Tail Block Rate ($/Therm)	0.2681	0.2323	0.3846	0.2564
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 220.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-42B is $83.82 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas' rate G-42 is $2.38. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-42B designed with a $39.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

3. Rate G-43B (C&I High Use, Low Load Factor

The G-43B rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 222). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $147.14 (Exh. NG-AEL-5, at 222). National Grid's current and proposed rate G-43B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-43B	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	147.14	147.14	147.14	147.14
Head Block Size (Therms)	N/A	N/A	900	300
Head Block Rate ($/Therm)	0.2149	0.1863	0.2592	0.1737
Tail Block Rate ($/Therm)	0.2149	0.1863	0.3231	0.2154
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 222.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-43B is $195.03 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas' rate G-43 is $19.39. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-43B designed with a $100.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

4. Rate G-44B (C&I Extra-High Use, Low Load Factor

The G-44B rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 224). The G-44B class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. NG-AEL-5, at 224). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $590.89 (Exh. NG-AEL-5, at 224). National

Grid's current and proposed rate G-44B distribution charges for Boston Gas are as shown in the following table.

Rate G-44B	Current		Proposed	
	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	590.89	590.89	590.89	590.89
Demand Rate ($/MDCQ Therm)	3.1448	1.0859	3.9446	2.6297
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 224.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-44B is $582.92 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas' rate G-53, which is available to customers with similar annual usage as rate G-44B, is $300.00. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-44B designed with a $443.00 monthly customer charge best meets our rate design goals and objectives. The demand rate for the peak and off-peak season shall be calculated to recover the remaining target revenues to be collected in that season through the demand charge. As approved above, the peak and off-peak revenue requirement shall be calculated using the allocation factor proposed by National Grid for assigning the class revenue requirement to the peak and off-peak seasons.

5. Rate G-51B (C&I Low Use, High Load Factor

The G-51B rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 225). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $28.97 (Exh. NG-AEL-5, at 225). National Grid's current and proposed rate G-51B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-51B	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	28.97	28.97	28.97	28.97
Head Block Size (Therms)	N/A	N/A	60	45
Head Block Rate ($/Therm)	0.2815	0.2480	0.2681	0.2444
Tail Block Rate ($/Therm)	0.2815	0.2480	0.3337	0.3034
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 225.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-51B is $33.18 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas' rate G-51 is $8.14. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-51B designed with a $21.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

6. Rate G-52B (C&I Medium Use, High Load Factor)

The G-52B rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 227). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $52.14 (Exh. NG-AEL-5, at 227). National Grid's current and proposed rate G-52B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-52B	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	52.14	52.14	52.14	52.14
Head Block Size (Therms)	N/A	N/A	200	150
Head Block Rate ($/Therm)	0.2239	0.2046	0.2373	0.2169
Tail Block Rate ($/Therm)	0.2239	0.2046	0.2916	0.2651
Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 227.				

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-52B is $73.04 per month (Exh. NG-JDS-2, at 27). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-52B designed with a $39.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

7. Rate G-53B (C&I High Use, High Load Factor

The G-53B rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through

August (Exh. NG-AEL-5, at 229). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $147.14 (Exh. NG-AEL-5, at 229). National Grid's current and proposed rate G-53B distribution charges for Boston Gas are as shown in the following table.

	Current		Proposed	
Rate G-53B	Boston Gas		Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	147.14	147.14	147.14	147.14
Head Block Size (Therms)	N/A	N/A	700	450
Head Block Rate ($/Therm)	0.1828	0.1758	0.2052	0.1870
Tail Block Rate ($/Therm)	0.1828	0.1758	0.2548	0.2316

Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 229.

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-53B is $151.37 per month (Exh. NG-JDS-2, at 27). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-53B designed with a $100.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

8. Rate G-54B (C&I Extra-High Use, High Load Factor

The G-54B rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 231). The G-54B class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. NG-AEL-5, at 231). National Grid proposes to keep the monthly customer charge for Boston Gas customers in this rate class at the current level of $590.89 (Exh. NG-AEL-5, at 231). National Grid's current and proposed rate G-54B distribution charges for Boston Gas are as shown in the following table.

Rate G-54B	Current Boston Gas		Proposed Boston Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	590.89	590.89	590.89	590.89
Demand Rate ($/MDCQ Therm)	3.1421	1.0875	3.4837	3.1670

Exhs. NG-JDS-2-2-BGC, at 1; NG-AEL-5, at 231.

According to the Boston Gas-Essex Gas ACOSS, the embedded customer charge for rate G-54B is $780.59 per month (Exh. NG-JDS-2, at 27). The current customer charge for Essex Gas rate G-53, which is available to customers with similar annual usage as rate G-54B, is $300.00. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-54B designed with a $443.00 monthly customer charge best meets our rate design goals and objectives. The demand rate for the peak and off-peak season shall be calculated to recover the remaining target revenues to be collected in that season through the demand charge. As approved above the peak and off-peak revenue requirement shall be calculated using the allocation factor proposed by National Grid for assigning the class revenue requirement to the peak and off-peak seasons.

G. Boston Gas Street Lighting and Outdoor Gas Lighting Analyses

1. Rate G-7 (Street Lighting

Rate G-7 is available to any street lighting customer (Exh. NG-AEL-5, at 232). National Grid proposes for Boston Gas a monthly fixed charge, which will increase from $14.01 to $16.28 per lamp (Exhs. NG-AEL-5, at 232; NG-JDS-2-4-BGC at 12). According to National Grid, the monthly base distribution rate per lamp is calculated by dividing the class revenue target by the number of test year lamps (Exh. NG-JDS-2, at 32). In addition, National Grid proposes to calculate the base revenue target as the increase in pro forma base revenues that would result in a total increase, including GAF and LDAF rates, equal to Boston Gas' overall increase of 6.53 percent (Exh. NG-JDS-2, at 32).

Because this service is unmetered, the Department finds that National Grid's method for calculating Boston Gas' street lighting rate is acceptable. Accordingly, the Department directs National Grid in its compliance filing to this Order to set a monthly fixed charge that would recover the class' revenue requirements, as discussed above.

2. Rate G-17 (Outdoor Gas Lighting

The G-17 rate is available to all customers for outdoor gas lighting where a standard gas light on private property cannot be metered along with the gas used for other purposes by the customer (Exhs. NG-AEL-5 at 233; NG-JDS-2-4-BGC, at 14). National Grid proposes a peak and off-peak monthly charge of $28.46 per lamp for Boston Gas, which is a decrease from the current peak and off-peak monthly charge of $28.97 per lamp (Exh. NG-AEL-5 at 233).

Because this service is unmetered, the Department finds Boston Gas' method for determining its proposed rate to be acceptable. Accordingly, the Department directs National Grid, in its compliance filing to this Order, to set the monthly fixed charge that would recover the class' revenue requirements as discussed above.

H. Essex Gas Commercial and Industrial Rate-by-Rate Analysis

1. Rate G-41E (C&I Low Use, Low Load Factor

The G-41E rate is available to C&I customers whose normal annual use is 22,000 therms or less and whose metered use in the most recent peak period of

November through April is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 218). National Grid proposes to increase Essex Gas' monthly customer charge from its current rate of $6.83 to $28.97 (Exh. NG-AEL-5, at 219, 242). National Grid's current and proposed rate G-41E distribution charges for Essex Gas are as shown in the following table.

	Current		Proposed	
Rate G-41E	Essex Gas		Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	6.83	6.83	28.97	28.97
Head Block Size (Therms)	350	50	120	35
Head Block Rate ($/Therm)	0.3715	0.2568	0.2453	0.1570
Tail Block Rate ($/Therm)	0.3614	0.2268	0.3018	0.1947
Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 219.				

According to Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-41E is $59.76 per month (Exh.NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-41 is $28.97. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-41E designed with a $21.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

2. Rate G-42E (C&I Medium Use, Low Load Factor

The G-42E rate is available to C&I customers whose normal annual use is greater than 22,000 therms but equal to or less than 100,000 therms and whose metered use in the most recent peak period of November through April is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 221). National Grid proposes to increase Essex Gas' monthly customer charge from its current rate of $2.38 to $52.14 (Exh. NG-AEL-5, at 221, 243). National Grid's current and proposed rate G-42E distribution charges for Essex Gas are as shown in the following table.

	Current		Proposed	
Rate G-42E	Essex Gas		Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	19.39	19.39	52.14	52.14
Head Block Size (Therms)	N/A	N/A	1040	300
Head Block Rate ($/Therm)	0.3108	0.1863	0.2635	0.1779
Tail Block Rate ($/Therm)	0.3108	0.1863	0.3268	0.2178
Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 221.				

According to the Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-42E is $192.99 per month (Exh.NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-42 is $52.14. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-42E designed with a $39.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

3. Rate G-43E (C&I High Use, Low Load Factor

The G-43E rate is available to C&I customers whose normal annual usage is greater than 100,000 therms and whose metered use in the most recent peak period of November through April is greater than or equal to 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 223). National Grid proposes to increase Essex Gas' monthly customer charge from its current rate of $19.39 to $147.14 (Exh. NG-AEL-5, at 223, 244).

National Grid's current and proposed rate G-43E distribution charges for Essex Gas are as shown in the following table.

	Current		Proposed	
Rate G-43E	Essex Gas		Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	19.39	19.39	147.14	147.14
Head Block Size (Therms)	N/A	N/A	2000	600
Head Block Rate ($/Therm)	0.3108	0.1610	0.2474	0.1642
Tail Block Rate ($/Therm)	0.3108	0.1610	0.3012	0.2008
Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 223.				

According to the Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-43E is $301.86 per month (Exh.NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-43 is $147.14. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-43E designed with a $100.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

4. Rate G-51E (C&I Low Use, High Load Factor

The G-51E rate is available to C&I customers whose normal annual usage is 45,000 therms or less and whose metered use in the most recent peak period of November through April is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 226). National Grid proposes to increase Essex Gas' monthly customer charge from its current rate of $8.14 to $28.97 (Exh. NG-AEL-5, at 226, 245). National Grid's current and proposed rate G-51E distribution charges for Essex Gas are as shown in the following table.

Rate G-51E	Current Essex Gas		Proposed Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	8.14	8.14	28.97	28.97
Head Block Size (Therms)	500	300	200	120
Head Block Rate ($/Therm)	0.3836	0.2509	0.2493	0.2279
Tail Block Rate ($/Therm)	0.3532	0.2209	0.3096	0.2814

Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 226.

According to the Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-51E is $73.91 per month (Exh. NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-51 is $28.97. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-51E designed with a $21.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

5. Rate G-52E (C&I Medium Use, High Load Factor)

The G-52E rate is available to C&I customers whose normal annual usage is greater than 45,000 therms and less than or equal to 180,000 therms and whose metered use in the most recent peak period of November through April is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 228). National Grid's current and proposed rate G-52E distribution charges for Essex Gas are as shown in the following table.

	Current		Proposed	
Rate G-52E	Essex Gas		Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	273.17	273.17	52.14	52.14
Head Block Size (Therms)	N/A	N/A	2000	2000
Head Block Rate ($/Therm)	0.3108	0.1609	0.2218	0.2084
Tail Block Rate ($/Therm)	0.3108	0.1609	0.2775	0.2523
Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 228.				

According to the Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-52E is $253.37 per month (Exh. NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-52 is $52.14. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-52E designed with a $39.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

6. Rate G-53E (C&I High Use, High Load Factor

The G-53E rate is available to C&I customers whose normal usage is greater than 180,000 therms and whose metered use in the most recent peak period of November through April is less than 73 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 230). The G-53E class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. NG-AEL-5, at 230). National Grid proposes to increase Essex Gas' monthly customer charge from its current rate of $300.00 to $590.89 (Exh. NG-AEL-5, at 230, 247). National Grid's current and proposed rate G-53E distribution charges for Essex Gas are as shown in the following table.

	Current		Proposed	
Rate G-53E	Essex Gas		Essex Gas	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	300.00	300.00	590.89	590.89
Demand Rate ($/MDCQ Therm)	8.2400	3.1500	4.2962	3.9056
Exhs. NG-JDS-2-2-BGC, at 2; NG-AEL-5, at 230.				

According to the Boston Gas-Essex Gas' ACOSS, the embedded customer charge for rate G-53E is $551.69 per month (Exh. NG-JDS-2, at 27). The current customer charge for Boston Gas' rate G-53E is $590.89. Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-53E designed with a $443.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

I. Colonial Gas Residential and Commercial and Industrial Rate-by-Rate Analysis

1. Rate R-1, R-2, R-3 and Rate R-4 (Residential Non-Heating and Heating

a. Introduction

Rate R-1 is available to all residential customers who do not have gas space-heating equipment, while rate R-3 is available to all residential customers who have gas space-heating equipment. Both R-1 and R-3 require that a customer take service through one meter in a single building that contains no more than four dwelling units (Exh. NG-AEL-5, at 250-252). The current monthly customer charges for rate R-1 customers of Colonial Gas-Cape and Colonial Gas-Lowell are $6.42 and $4.94, respectively (Exh. NG-AEL-5, at 250, 264).

National Grid's current and proposed rate R-1 and R-3 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate R-1	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	4.94	4.94	6.42	6.42	10.98	10.98
Head Block Size (Therms)	25	15	25	20	10	5
Head Block Rate ($/Therm)	0.8453	0.7733	1.0391	0.9567	0.5338	0.4873
Tail Block Rate ($/Therm)	0.5636	0.4933	0.7156	0.6367	0.6641	0.6037
Rate R-3						
Customer Charge ($)	4.94	4.94	6.42	6.42	13.89	13.89
Head Block Size (Therms)	50	N/A	50	30	40	10
Head Block Rate ($/Therm)	0.4639	0.0933	0.5991	0.3269	0.3228	0.2509
Tail Block Rate ($/Therm)	0.4339	0.0933	0.3703	0.0998	0.3845	0.2958

Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 250 and 252.

Rate R-2 is a subsidized rate that is available at single locations to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Exh. NG-AEL-5, at 251). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See D.P.U. 08-104.

Rate R-4 is a subsidized rate that is available at single locations to residential customers for domestic heating purposes in private dwellings and individual apartments (NG-AEL-5, at 253). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See D.P.U. 08-104, at 2-3.

The Department has approved for Colonial Gas a low-income discount rate of 25 percent applied to the total bill. D.P.U. 10-41 through D.P.U. 10-48, at 18. In addition, the Department has approved the Companies' proposal for Colonial Gas distribution rates that become effective November 2, 2010, to have the R-1 charges be the same as the R-2 charges and the R-3 charges be the same as the R-4 charges. D.P.U. 10-41 through 10-48, at 4-5, 18.

National Grid's current and proposed rate R-2 and R-4 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate R-2	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	3.20	3.20	4.51	4.51	10.98	10.98
Head Block Size (Therms)	25	15	25	20	10	5
Head Block Rate ($/Therm)	0.4773	0.4503	0.6302	0.6153	0.5338	0.4873
Tail Block Rate ($/Therm)	0.3062	0.2816	0.4059	0.3822	0.6641	0.6037
Rate R-4						
Customer Charge ($)	2.05	2.05	3.11	3.11	13.89	13.89
Head Block Size (Therms)	50	N/A	50	30	40	10
Head Block Rate ($/Therm)	0.1466	0.0058	0.2285	0.1202	0.3228	0.2509
Tail Block Rate ($/Therm)	0.1342	0.0058	0.1177	0.0102	0.3845	0.2958

Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 251 and 253.

b. Analysis and Findings

The current customer charges for the residential non-heating rate classes that are being consolidated range from a high of $6.42 per month to a low of $3.20 per month. The current customer charges for the residential heating classes that are being consolidated range from a high of $6.42 per month to a low of $2.05 per month. According to Colonial Gas' ACOSS, the embedded customer charges for rates R-1 and R-3 for Colonial Gas-Lowell are $21.07 and $24.81 per month, respectively. For Colonial Gas-Cape, the embedded customer charges for rates R-1 and R-3 are $13.26 and $16.47 per month, respectively (Exh. NG-JDS-2, at 45).

The Department has the difficult task of establishing a customer charge that satisfies our rate continuity and efficiency rate design goals where there are large variances in the current customer charges and, at the same, time achieves our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency. Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that: (1) R-1 and R-2 rates, designed with a $6.00 monthly customer charge; and (2) R-3 and R-4 rates designed with an $8.00 monthly customer charge best meet our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

2. Rate G-41 (C&I Low Use, Low Load Factor

National Grid proposes to make the G-41 rate available to C&I customers whose maximum hourly meter capacity is between zero and 20,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 254). National Grid's current and proposed rate G-41 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-41	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	2.97	2.97	10.37	10.37	28.97	28.97
Head Block Size (Therms)	600	N/A	240	50	120	30
Head Block Rate ($/Therm)	0.3228	0.1383	0.4669	0.1543	0.2346	0.1519
Tail Block Rate ($/Therm)	0.3027	0.1383	0.4466	0.1543	0.2855	0.1842

Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 254.

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-41 are $38.53 per month for Colonial Gas-Lowell and $20.21 per month for Colonial Gas-Cape (Exh.NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-41 designed with a $11.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

3. Rate G-42 (C&I Medium Use, Low Load Factor

National Grid proposes to make the G-42 rate available to C&I customers whose metered annual gas usage is greater than or equal to 20,001 therms and less than or equal to 100,000 therms and whose metered use in the most recent peak period of November through April is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 255). National Grid's current and proposed rate G-42 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-42	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	7.43	7.43	10.38	10.38	52.14	52.14
Head Block Size (Therms)	5,000	N/A	2,800	N/A	1,500	350
Head Block Rate ($/Therm)	0.2465	0.1283	0.3165	0.1018	0.2527	0.1672
Tail Block Rate ($/Therm)	0.2263	0.1283	0.2960	0.1018	0.3086	0.2057
Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 255.						

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-42 are $165.31 per month for Colonial Gas-Lowell and $112.40 per month for Colonial Gas-Cape (Exh.NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-42 designed with a $25.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

4. Rate G-43 (C&I High Use, Low Load Factor

National Grid proposes to make the G-43 rate available to C&I customers whose metered annual gas usage is greater than or 100,000 therms and whose metered use in the most recent peak period of November through April is greater than or equal to 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 256). National Grid's current and proposed rate G-43 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-43	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	14.87	14.87	49.13	49.13	147.14	147.14
Head Block Size (Therms)	17,000	N/A	25,000	N/A	7,000	2,500
Head Block Rate ($/Therm)	0.2173	0.1233	0.3103	0.0821	0.2033	0.1370
Tail Block Rate ($/Therm)	0.1972	0.1233	0.2851	0.0821	0.2462	0.1641

Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 256.

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-43 are $258.01 per month for Colonial Gas-Lowell and $345.64 per month for Colonial Gas-Cape (Exh.NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-43 designed with a $100.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

5. Rate G-51 (C&I Low Use, High Load Factor

National Grid proposes to make the G-51 rate is available to C&I customers whose metered annual gas usage is 20,000 therms or less and whose metered use in the most recent peak period of November through April is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 257). National Grid's current and proposed rate G-51 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-51	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	2.97	2.97	10.37	10.37	28.97	28.97
Head Block Size (Therms)	600	N/A	400	N/A	175	120
Head Block Rate ($/Therm)	0.3500	0.1283	0.4111	0.1494	0.2226	0.1989
Tail Block Rate ($/Therm)	0.3300	0.1283	0.3911	0.1494	0.2716	0.2469
Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 257.						

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-51 are $46.67 per month for Colonial Gas-Lowell and $28.00 per month for Colonial

Gas-Cape (Exh. NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-51 designed with a $11.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

6. Rate G-52 (C&I Medium Use, High Load Factor

National Grid proposes to make the G-52 rate available to C&I customers whose metered annual gas usage is greater than 20,000 therms and less than or equal to 100,000 therms and whose metered use in the most recent peak period of November through April is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 258). National

Grid's current and proposed rate G-52 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-52	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	7.41	7.41	10.38	10.38	52.14	52.14
Head Block Size (Therms)	7,000	N/A	2,000	N/A	1040	650
Head Block Rate ($/Therm)	0.2223	0.1183	0.3246	0.1013	0.2151	0.1956
Tail Block Rate ($/Therm)	0.2023	0.1183	0.3041	0.1013	0.2649	0.2408
Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 258.						

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-52 are $126.93 per month for Colonial Gas-Lowell and $80.94 per month for Colonial Gas-Cape (Exh. NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-52 designed with a $25.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

7. Rate G-53 (C&I High Use, High Load Factor)

National Grid proposes to make the G-53 rate available to C&I customers whose metered annual gas usage is greater than 100,000 therms and whose metered use in the most recent peak period of November through April is less than 72 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. NG-AEL-5, at 259). National Grid's current and proposed rate G-53 distribution charges for Colonial Gas-Lowell and Colonial Gas-Cape are as shown in the following table.

	Current				Proposed	
Rate G-53	Colonial-Lowell		Cololonial-Cape		Colonial	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Customer Charge ($)	14.86	14.86	49.48	49.48	147.14	147.14
Head Block Size (Therms)	25,000	N/A	N/A	N/A	10,000	9,000
Head Block Rate ($/Therm)	0.2092	0.1133	0.3015	0.0809	0.1501	0.1374
Tail Block Rate ($/Therm)	0.1840	0.1133	0.2762	0.0809	0.1843	0.1675
Exhs. NG-JDS-2-5-COL, at 1; NG-AEL-5, at 259.						

According to Colonial Gas' ACOSS, the embedded customer charges for rate G-53 are $317.22 per month for Colonial Gas-Lowell and $272.46 per month for Colonial Gas-Cape (Exh. NG-JDS-2, at 45). Based on a review of embedded costs, the seasonal and annual bill impacts on customers, and our objectives of establishing distribution charges that satisfy our rate design goals and, at the same time, achieve our objectives of aligning National Grid's gas rates across Massachusetts and lowering customers bills through increased end-use efficiency, the Department finds that a rate G-53 designed with a $100.00 monthly customer charge best meets our rate design goals and objectives. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above (i.e., (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by National Grid to assign the class revenue requirement to the peak and off-peak seasons).

J. Colonial Gas Outdoor Gas Lighting Rate Analysis - Rate G-17 (Outdoor Gas Lighting)

The G-17 rate is available to all customers for outdoor gas lighting where a standard gas light on private property cannot be metered along with the gas used for other purposes by the customer (Exhs. NG-AEL-5, at 260; NG-JDS-2-8-COL at 42). National Grid proposes a peak and off-peak monthly charge of $5.16 for Colonial Gas-Cape (Exh. NG-AEL-5, at 260).

Because this service is unmetered, the Department finds National Grid's method for determining its proposed rate to be acceptable. Accordingly, the Department directs National Grid in its compliance filing to this Order to set the monthly fixed charge that would recover the class' revenue requirements as discussed above.

K. Rates to be Terminated

1. Essex Gas Rate R-6

Essex Gas has two residential heating low-income rates, R-4 and R-6. The R-6 rate is available only to recipients receiving supplemental security income from the Social Security Administration. Rate R-6 was established in the early 1980s and was closed to new customers pursuant to D.P.U. 89-107 (Exhs. NG-JDS-2, at 8; NG-AEL-5, at 241). National Grid proposes to eliminate rate R-6 and place the two remaining customers onto rate R-4 (Exh. NG-JDS-2, at 8). The Department finds the Companies' proposal to be reasonable and, therefore, rate R-6 is terminated as of the effective date of this Order.

2. Colonial Gas' Cape Division Rate R-5

Colonial Gas-Cape currently offers residential seasonal rate R-5 to all residential users of gas (Exh. NG-JDS-2, at 15; Colonial Gas Company, Cape Code Division, M.D.T.E. 300). National Grid is proposing to discontinue this rate class and to move all rate R-5 customers to rate R-1 (Exh. NG-JDS-2, at 15). The Department has reviewed the bill impacts of customers on rate R-5 moving to rate R-1 and finds that the bill impacts do not violate our rate continuity goal. Moving the rate R-5 customers to rate R-1 will also simplify the Companies' rate structure. Therefore, the Companies' proposal to move the rate R-5 customers to rate R-1 is approved as of the effective date of this Order.

3. Colonial Gas Transportation Rates T-56, T-57, and T-58

Colonial Gas-Cape currently offers firm gas service to approximately 40 transportation customers on rates T-56, T-57, and T-58. These rates were closed to new customers after November 1, 2000, and these tariffs were to be eliminated at the time of Colonial Gas' next rate case (Exh. NG-JDS-2, at 15). The Department has reviewed the bill impacts of moving these customers to rates G-41, G-42, G-51, G-52, or G-53 and finds that the bill impacts do not violate our rate continuity goal. Further, these rates were intended to be eliminated at the time of Colonial Gas' next rate case. Therefore, the Department approves the Companies' proposal to eliminate Colonial Gas-Cape's rates T-56, T-57, and T-58 as of the effective date of this Order.

L. Tariff Numbering System

Presently, National Grid relies on a specific tariff numbering system. The CGAC, LDAC, and distribution service terms and conditions tariffs are shared by all three companies, under the d/b/a name "National Grid" (Exh. NG-AEL-5, at 2-211). Distribution tariffs are numbered by series, with Boston Gas using a 100-series numbering system, Essex Gas using a 200-series numbering system, and Colonial Gas using a 300 series numbering system (Exh. NG-AEL-5, at 213-283). National Grid has proposed to maintain this distinctive numbering system (Exh. NG-AEL-4, at 1-191).

Under G.L. c. 164, § 94, a utility's proposed rates must be found as consistent with the public interest. One component of this standard, applicable to tariff construction, requires that a proposed tariff have sufficient detail to explain the basis for the rate to be charged for the offered service. Boston Gas Company, D.P.U. 92-259, at 47-48 (1993); Dedham Water Company, D.P.U. 13271, at 10 (1961). The Department's regulations prescribe tariff construction. For example, pursuant to 220 C.M.R. § 5.02(3)(a), each tariff or schedule shall show prominently the name of the company, firm, association or individual responsible, together with the name of any independent agency filing the tariff or schedule and its or his address. Moreover, each tariff or schedule must be designated by an individual number progressing from that last filed by the same party or in case of a new series, from Number 1 and sequentially thereafter. 220 C.M.R. § 5.04(a). National Grid's tariff numbering system fails to comply with the Department's regulations. Moreover, the Companies' current and proposed tariff numbering system creates the false impression that "National Grid" is a gas distribution company in its own right; such is not the case. See D.P.U. 09-139, at 32-34. Finally, the use of the d/b/a "National Grid" by multiple companies results in customer confusion.

Therefore, in order to prevent customer confusion and ensure compliance with Department regulations, the Companies are directed to submit, as part of their respective compliance filings, tariffs that clearly identify the legal business name of the particular company (i.e., Boston Gas or Colonial Gas, as applicable).[329] Additionally, the Companies are directed to renumber their tariffs sequentially as required by 220 C.M.R. § 5.04(a).

XIII. SERVICE QUALITY

A. Introduction

During the proceeding, there were several issues raised by NEGWA regarding the Companies' service quality (see e.g., NG-AEL-4, at 35, 52; NEGWA-MM-1, at 3). NEGWA argues that National Grid's actions jeopardize the safety, quality, rates, and reliability of

[329] If the Companies wish to include the d/b/a "National Grid" in their tariffs, they may do so, provided that it is clear that "National Grid" is only being used as part of a d/b/a arrangement.

service to customers as well as compromise employee safety (Exh. NEGWA-MM-1, at 3). As outlined below, NEGWA raises concerns about: (1) grade 1 leaks; (2) the use of plastic pipeline technology; (3) the testing of gas meters; (4) the replacement of service lines; (5) the shutting off of gas from the street; and (6) service disconnections (NEGWA Brief at 1-9; NEGWA Reply Brief at 1-4). National Grid denies that any of these issues present service quality concerns (National Grid Brief at IV.32-33). No other party addressed these issues. We discuss each of these service quality-related issues below.[330]

B. Grade 1 Leaks

1. Introduction

Pursuant to industry standards outlined by the American Gas Association Gas Piping Technology Committee, gas leaks are classified: (1) grade 1 leaks, which require immediate and continuous action until the hazard no longer exists; (2) grade 2 leaks, which require periodic monitoring; and (3) grade 3 leaks, which are considered non-hazardous at the time of detection and are expected to remain non-hazardous (Exh. NG-WJA-1, at 10; Tr. 4, at 345-346).

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[330] In addition to the issues raised by NEGWA, we note that National Grid originally proposed to combine the service quality measures and benchmarks for Boston Gas and Essex Gas (see Exh. NG-AEL-4, at 35, 52). During the proceeding, however, National Grid agreed to continue to maintain separate service quality measures and benchmarks for Boston Gas and Essex Gas, consistent with the Department's recent decision in D.P.U. 09-139, at 24-25 (see RR-DPU-116; RR-DPU-118, Att. (A) at 3, 9, 22; RR-DPU-118, Att. (B) at 3, 10, 24-25). The Department directs the Companies to maintain and report separate service quality measures and benchmarks for Boston Gas, Essex Gas, and Colonial Gas.

2. Positions of the Parties

a. NEGWA

NEGWA asserts that National Grid has undertaken a pilot program that has adversely changed its policy regarding monitoring and repair of grade 1 leaks (NEGWA Brief at 3). According to NEGWA, under this pilot program, grade 1 leaks are monitored once a day and can go unrepaired for weeks (NEGWA Brief at 3, citing Exh. NEGWA-MM-1, at 5). NEGWA requests that the Department require the Companies to monitor grade 1 leaks more closely and not leave them unattended (NEGWA Reply Brief at 3, 8).

b. National Grid

National Grid argues that NEGWA mischaracterizes the Companies' pilot program to manage and repair leaks (National Grid Brief at IV.32). National Grid asserts that its pilot program was developed with significant input from the Department's pipeline safety division staff and is an enhancement of the Companies' prior procedures (National Grid Brief at IV.32). National Grid maintains that under the pilot program, the Companies do not temporarily downgrade grade 1 leaks through interim repairs; instead, the leaks remain classified as grade 1 events and are continuously monitored until they are able to be permanently repaired (National Grid Brief at IV.33). National Grid asserts that the pilot program also provides for extensive reexamination of conditions at the location after repairs have been performed in order to ensure that the repairs are permanent (National Grid Brief at IV.33).

3. Analysis and Findings

All gas operator leak investigation programs are required to comply with both the federal and state pipeline safety regulations that require all hazardous leaks to promptly be made safe and permanent repairs instituted. 49 C.F.R Part 192, § 192.703(c); 220 C.M.R. § 101.06 (21)(e). As an initial matter, we note that National Grid's pilot program for grade 1 leaks is limited to the city of Boston (Tr. 4, at 347). We determine that Boston Gas continues to follow industry practice in that it immediately responds to a grade 1 leak and mitigates the leak to keep the gas from getting into buildings, thereby reducing the immediate hazard (Exh. NG-WJA-JBH-Rebuttal-1, at 7; Tr. 4, at 346-347, 352). Under the pilot program, however, rather than reclassifying the leak as a grade 2 once the mitigation steps have been taken, Boston Gas retains the grade 1 classification (Exh. NG-WJA-JBH-Rebuttal-1, at 7-8; Tr. 4, at 347).

There is no evidence to demonstrate that the pilot program for grade 1 leaks is inconsistent with federal and state pipeline safety regulations. The Department continues to monitor all gas companies' pipeline safety and, where we determine a company is not in compliance with these regulations, the Department will exercise its authority pursuant to G.L. c. 164, § 105A and 220 C.M.R. §§ 69.00 et seq. and direct appropriate remedial action.

C. Plastic Pipeline Technology

1. Introduction

National Grid's Massachusetts distribution system includes 4,086 miles of mains that are classified as plastic pipe, representing 37 percent of the Companies' total mains (Exh. NG-JBH-1, at 8). In addition, National Grid's total Massachusetts distribution system includes 334,906 of services that are categorized as plastic pipe, representing 48 percent of total services (Exh. NG-JBH-1, at 8). The remaining distribution system is composed of non-cathodically protected steel, cathodically protected steel, cast iron, wrought iron, copper, or undetermined composition (Exh. NG-JBH-1, at 8).

2. Positions of the Parties

a. NEGWA

NEGWA argues that there are serious questions about the durability and safety of plastic pipe as well as the grade of tracer wire used in conjunction with plastic pipes (NEGWA Brief at 5, citing, e.g., Exhs. NEGWA-MM-Rebuttal-1, at 3-4; NG-NEGWA-33, 34, 37). For example, NEGWA asserts that plastic pipes can turn brittle over time as a result of incorrect installation, improper handling, ultra-violet damage, soil conditions and age (NEGWA Brief at 5). Further, NEGWA contends that plastic pipe is more easily damaged than steel pipe (NEGWA Brief at 5, citing Exh. NEGWA-MM-Rebuttal-1, at 4). In addition, NEGWA claims that National Grid does not use the industry-accepted grade of tracer wire for non-direct burial applications (NEGWA Reply Brief at 3, citing Exh. NEGWA-MM-Rebuttal-1, at 3). Therefore, NEGWA requests that the Department open an investigation to determine the safety and durability of plastic pipeline technology (NEGWA Reply Brief at 8).

b. National Grid

The Companies argue that NEGWA's concerns over plastic pipe raises are misplaced (National Grid Brief at IV.34). National Grid maintains that the industry has extensive performance data on the use of plastic pipe and the Companies' data confirm that plastic pipe has had a lower damage rate than cast iron (National Grid Brief at IV.34, citing RR-NEGWA-11).

3. Analysis and Findings

Federal pipeline safety regulations prescribe the type of plastic pipe that is approved for use in the transportation of natural gas. 49 C.F.R. Part 192, § 192.59. Plastic pipe must be manufactured and installed in accordance with listed specifications for natural gas service. 49 C.F.R. Part 192, § 192.13, § 192.59. In addition, each valve, fitting, length of pipe, and other component must be marked to identify the specification standard to which it was manufactured and to ensure that the required pipe is used for natural gas service. 49 C.F.R. Part 192, § 192.63(a) (Marking of Materials); see 49 C.F.R. Part 192, § 192.121 (Design of Plastic Pipe), § 192.123 (Design Limitations of Plastic Pipe).[331]

In 1999, the federal government formed the Plastic Pipe Database Committee ("PPDC") to develop a process for gathering data on future plastic pipe failures. AD-B99-02, 47 FR 12212 (March 11, 1999).[332] The PPDC database was designed to improve the

331 The American Society for Testing and Materials specification D2513 ("ASTM D2513") outlines the required specification for all gas operators to use for plastic pipe for natural gas. 49 C.F.R. Part 192, § 192.7 (ASTM D 2513 Incorporated by Reference). The ASTM D 2513 specification limits the amount of time plastic pipe can be exposed to ultra-violet rays to no more than two years.

332 Members of the PPDC include the American Gas Association, the American Public Gas Association, the Plastic Pipe Institute, the National Association of Regulatory Utility Commissioners, the National Association of Pipeline Safety Representatives, and the Office of Pipeline Safety ("OPS") of the U.S. Department of Transportation ("USDOT").

knowledge base of gas utility operators and regulators and to help reveal any failure trends associated with older plastic piping materials.[333]

National Grid has been using plastic and other non-leak-prone pipes because following installation, the potential for leaks unrelated to damage incidents is virtually eliminated (Exh. NG-JBH-1, at 11, 12-13, 23; RR-AG-14; see Tr. 4, at 327, 345, 387). In addition, National Grid has procedures that address the collection of information pertaining to pipeline failures, reporting failures, as well as review process for evaluating systemic problems (see, e.g., Exh. NG-WJA-1, at 8-10, 12-13; Tr. 4, at 312-313, 337; 342-343). For example, the Companies conduct leak surveys at a frequency that meets or exceeds applicable USDOT pipeline safety regulations (Exh. NG-WJA-1, at 9-10; Tr. 4, at 342-343).

In considering damage to plastic pipes, the record demonstrates that in 2009, National Grid's mains composed of plastic pipe had a lower damage rate than other materials, including cast iron and steel while damage to services composed of plastic pipe were comparable to other materials (RR-NEGWA-11; see Tr. 4, at 345, 387). In addition, plastic material is considered safer because it typically breaks at the point of third-party contact, at which point the damage can be readily observed and repaired, unlike steel or iron mains where damage may cause a delayed leak that migrates to a remote and undisclosed location

[333] The U.S. Department of Transportation, Research and Special Programs Administration issued two advisory bulletins addressing concerns of brittle cracking of polyethylene pipe. The first advisory bulletin notified natural gas distribution system operators of the potential poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. ADB-99-01, 47 FR 12211 (March 11, 1999). The second advisory bulletin notified natural gas distribution system operators of the potential for brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s. ADB-99-02, 47 FR 12212 (March 11, 1999).

(Exh. NG-WJA/JBH-Rebuttal-1, at 15). There is contradictory evidence as to whether the Companies are installing the appropriate tracer wire (see Exhs. NEGWA-MM-Rebuttal-1, at 3; NG-WJA/JBH-Rebuttal-1, at 15-16; Tr. 18, at 2535 2536). To the extent that National Grid is using the appropriate tracer wire in each situation, we expect the Companies to continue this practice. If National Grid is using AWG No. 12 stranded wire as tracer wire, however, we direct them to cease this practice forthwith and commence using AWG No. 10 stainless steel wire instead. Therefore, we find that National Grid is appropriately using plastic pipe in its distribution system and we decline to open an investigation to determine the safety and durability of plastic pipeline technology.

D. Testing Meters for Leaks

1. Introduction

NEGWA argues that National Grid's leak testing for meters is limited to accuracy and, thus, is not adequate for detecting leaks (NEGWA Brief at 6; NEGWA Reply Brief at 4, citing Exh. NEGWA-MM-1, at 7). NEGWA asserts that only large leaks can be detected by applying slight pressure to engage the meter's dials and smaller leaks cannot be found at all (NEGWA Brief at 6; NEGWA Reply Brief at 4). NEGWA requests that the Department direct the Companies to conduct more rigorous testing of all meters for leaks before placing them in service (NEGWA Reply Brief at 8). National Grid did not comment on NEGWA's claims.

2. Analysis and Findings

Massachusetts law requires testing to ascertain and prove the accuracy of all meters that are used for measuring gas and are furnished to any consumer or company, as well as random sampling testing of new gas meters to ensure accurate operation. G.L. c. 164, § 103; see 220 C.M.R. § 36.01. In addition, meters must be replaced every seven years with a meter that has been newly tested by the Commonwealth. G.L. c. 164, § 115A. The record demonstrates that National Grid conducts its own testing above these state requirements as part of its determination of whether to repair a used meter or replace it with a new meter (Exh. NG-WJA/JBH-Rebuttal-1, at 9).[334]

The Companies have not experienced any systemic problem with meters returned to service after testing (Exh. NG-WJA/JBH-Rebuttal-1, at 9). Because the Companies are complying with applicable law and there is nothing in the record to indicate that the Massachusetts requirements are inadequate, we decline to direct the Companies to conduct more rigorous testing of all meters for leaks before placing them in service.

[334] NEGWA asserts that National Grid has revised its meter policy to replace used meters in need of minor repair with new meters (NEGWA Brief at 10, citing Exh. NEGWA-MM-1, at 19). NEGWA asserts that a low cost employee could repair the meters for $5, representing a lower cost than the alternative of purchasing new meters for $75 per meter, resulting in annual additional costs to customers of between $800,000 and $1,600,000 (NEGWA Brief at 10, citing Exhs. NEGWA-MM-1, at 19; NG-NEGWA-2-42). In response, National Grid represents that meter repair costs have increased nearly three-fold between 2002 and 2009 (National Grid Brief at IV.35, citing Exh. NEGWA-2-44). The Companies also assert that they are continuing to study the economic feasibility of repairing versus replacing meters (National Grid Brief at IV.35). At this time, there is insufficient evidence regarding NEGWA's repair estimates to determine whether National Grid's current practice regarding used meters is imprudent. Thus, the Department directs the Companies to continue studying this issue and report on their findings as part of National Grid's next rate case.

E. Replacing Service Lines in Conjunction with Mains

1. Introduction

As part of the Companies' proposed TIRF, National Grid proposes to accelerate the replacement of leak-prone distribution facilities (Exhs. NG-NS-1, at 4, 7; NG-JBH-1, at 9, 11-12). Specifically, the Companies propose a structured replacement of its relatively higher risk distribution infrastructure (Exh. NG-JBH-1, at 25, 35). National Grid also proposes to replace any non-cathodically protected services associated with the mains that are replaced but it does not propose to replace all types of services (see Exh. NG-JBH-1, at 37-38). A more complete explanation of National Grid's infrastructure replacement program is provided in Section VI, above.

2. Positions of the Parties

a. NEGWA

NEGWA notes that National Grid concedes that it often leaves old services in place when it replaces associated pipeline (NEGWA Brief at 6, citing Exh. NG-WJA/JBH-Rebuttal-1, at 16; NEGWA Reply Brief at 4). NEGWA asserts that because these services are the same age as the pipe being replaced, they are often corroded or leaking and under-sized, and not well supported structurally (NEGWA Brief at 6, citing Exh. NEGWA-MM-Rebuttal-1, at 3-4; NEGWA Reply Brief at 4). Accordingly, NEGWA requests that the Department direct the Companies to replace all associated services when it replaces a pipeline (NEGWA Reply Brief at 4, 8).

b. National Grid

National Grid rejects NEGWA's assertion that perfectly sound pipe be replaced, regardless of its integrity or soundness (National Grid Brief at IV.35). National Grid argues that such a practice would plainly favor NEGWA's union members by providing them with more work, but would needlessly drive up the Companies' cost of service with no appreciable impact on service quality or public safety (National Grid Brief at IV.35).

3. Analysis and Findings

Gas operators require that qualified personnel perform inspections of the components associated with the gas service line whenever a company replaces or restores a gas service. 49 C.F.R. Part 192, § 192.805 (Operator Qualification). Further, gas operators are required to periodically inspect steel gas pipelines for atmospheric corrosion. 40 C.F.R. Part 192, § 192.481. In addition, operators are required to perform periodic leak surveys on all service lines, including inside piping up to the meter. 49 C.F.R. Part 192, § 192.723 (leakage surveys).

However, pipeline safety regulations do not require customer piping to be replaced at the time of a service line replacement. Rather, each company must conduct an inspection to ensure compliance with federal and state guidelines. Here, National Grid has demonstrated that it replaces services as warranted by an inspection of the condition of the facilities at the time of installation (Exh. NG-WJA/JBH-Rebuttal-1, at 16). In addition, the record shows that piping and related facilities inside premises are subject to less corrosion than the outside portion of the service and, in these instances, the service may be suitable for reuse and not require replacement (Exh. NG-WJA/JBH-Rebuttal-1, at 16).

Further, it would be neither reasonable nor cost-effective to require the Companies to implement wholesale replacement of services where such replacement is unwarranted by inspection and testing. Thus, we decline to direct the Companies to replace all associated services when it replaces a pipeline.

F. Gate Boxes

1. Introduction

A gate box[335] is a device installed on a gas main to permit shut-off in the event of an emergency. Because of the role a gate box plays in emergency response situations, Department regulations require that the location and accessibility of a gate box must be readily ascertainable by gas company personnel. 220 C.M.R. § 101.06(14).[336]

335 A gate box is a type of distribution valve as described at 49 C.F.R. Part 192, § 192.181, and curb valve or curb shutoff as described in the Department's regulations at 220 C.M.R. § 101.06(14).

336 All of the gas companies and municipal gas departments in Massachusetts also install excess flow valves on new or replaced service lines, where possible. See 49 C.F.R. Part 192, §§ 192.381, 192.383. An excess flow valve is a safety device that can terminate flow of gas through a pipeline when the flow rate exceeds its design level, such as when the pipe ruptures or is broken (e.g., by excavation damage) downstream of the valve. These valves can protect individual gas customers' properties from the consequences of a break in the service line associated with their property.

2. Positions of the Parties

a. NEGWA

Because they have been paved over, NEGWA asserts that many of the Companies' gate boxes are inaccessible in violation of Department regulations (NEGWA Brief at 7-8, citing 220 C.M.R. § 101.06(14)). NEGWA contends that in the event of a fire, access to safe shut-off is essential and asserts that gate boxes constitute the only reliable means of a safe shut-off (NEGWA Brief at 7, 9; NEGWA Reply Brief at 4, citing Exhs. NEGWA-MM-1, at 4; NEGWA-MM-Rebuttal-1, at 2). NEGWA argues that the Companies' actual strategy for dealing with the lack of outside shutoff valves may be to rely on primary valves instead of gate boxes at the curb (NEGWA Brief at 8). NEGWA asserts, however, that because of the limited number of primary valves, a major effort is required to restore service after a shut-off of those primary valves (NEGWA Brief at 8-9). Thus, NEGWA proposes that the Department require that National Grid undertake a ten-year inspection and remediation program for all gate boxes (NEGWA Brief at 9; NEGWA Reply Brief at 8).

b. National Grid

National Grid argues that NEGWA's allegations in this proceeding regarding covered gate boxes serve no legitimate purpose (National Brief at IV.34). National Grid asserts that this issue has been explored extensively by the Department and the Companies are complying with the Department's requirements in this area (Company Brief at IV.34-35).

3. Analysis and Findings

The Department has conducted two investigations into the issue of gate boxes. Investigation Re: Gate Box Maintenance and Improvement Requirements of

G.L. c. 164, § 116B, D.T.E./D.P.U. 06-48-A (2008); Report Re: Section 92 of the Green Communities Act, D.P.U. 09-36 (2009). In D.T.E./D.P.U. 06-48-A at 21-26, Att. A, the Department established a method to ensure enhanced communications among cities, towns and other governmental agencies and the gas operators with respect to maintenance and improvement of gate boxes as required by G.L. c.164, § 116B ("Section 116B").[337] The Department directed all gas operators to meet the following requirements:

> (1) identify visually, or through accurate records, the location of any gate box in all Commonwealth or city or town streets, roads or sidewalks subject to G.L. c. 164, § 116B; and
>
> (2) conduct an inspection program to confirm the location and maintain the accessibility of each gate box in item (1).

D.T.E./D.P.U. 06-48-A at 26.

In D.P.U. 09-36, at 8, the gas operators provided the Department with the estimated costs to comply with Section 116B. Based on the estimates provided, the Department determined that such costs would not have an adverse impact on customers' rates. Thus, the Department concluded that the public safety benefits of accessibility of gate boxes in public ways to shut off gas in the event of an emergency outweighed the cost of the gas operators' Section 116B compliance programs as prescribed in D.T.E./D.P.U. 06-48A. D.P.U. 09-36, at 8. As a result, the Department directed gas operators, including the Companies, to comply

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[337] Section 116B provides in pertinent part as follows: "Whenever the [C]ommonwealth or a city or town undertakes the repair of streets, roads or sidewalks the appropriate gas company shall provide for the maintenance and improvements of its gate boxes located in the streets, roads or sidewalks to be repaired, so that the gate boxes are more easily and immediately accessible."

with the directives set forth in D.T.E./D.P.U. 06-48-A. Specifically, gas operators are required to either raise gate boxes that have been paved over since the effective date of Section 116B or provide a reasonable alternative that otherwise ensures continued public safety. These safety requirements must be met within five years of the effective date of the Order in D.T.E./D.P.U. 06-48-A (i.e., no later than October 14, 2013). D.P.U. 09-36, at 5, citing D.T.E./D.P.U. 06-48-A at 28. Where an operator is unable to raise a paved-over gate box, the Department directed the gas operator to provide its employees accurate records, or maps, indicating their location. D.P.U. 09-36, at 5, citing D.T.E./D.P.U. 06-48-A at 28-29.

On March 31, 2010, National Grid provided its most recent report to the Department in compliance with D.P.U. 06-48-A and D.P.U. 09-36 (Exh. NG-WJA/JGB-Rebuttal-1, at 6; see D.T.E./D.P.U. 06-48-A, Letter from National Grid regarding Gate Box Maintenance and Improvement Requirement, March 31, 2010). The Companies identified approximately 200 known locations of gate valves that were buried during 2009 (Exh. NG-WJA/JGB-Rebuttal-1, at 6). National Grid also reported that it had raised and remedied close to 7,000 gate boxes prior to municipal paving projects (Exh. NG-WJA/JGB-Rebuttal-1, at 6).

In addition, as part of National Grid's collective bargaining agreement with its unions, National Grid has obtained the right to use a municipality and its paving contractor to inspect and raise gate boxes, where necessary, which is expected to reduce the incidence of buried gate boxes (Exhs. NG-WJA/JGB-Rebuttal-1, at 6-7; NG-WJA-2, at 1). The Companies are required to follow directives for ensuring accessibility of gate boxes as established in D.T.E./D.P.U. 06-48-A and communicate their compliance with such directives to the

Department. D.T.E./D.P.U. 06-48-A at 32. Thus, we decline to take any further action on this matter in this proceeding.

G. Service Disconnections

1. Introduction

Historically, when a customer closed an account due to a move from the premises, National Grid dispatched a technician to turn off the gas supply, and another technician was dispatched to turn the gas supply back on when the new customer requested service (Exh. NG-WJA/JBH-Rebuttal-1, at 3). National Grid revised its policy and now conducts what is referred to as a "soft disconnect," which means that service is no longer physically disconnected, but rather the meter is read when service is terminated and again when it is reinitiated (Exhs. NG-WJA/JBH-Rebuttal-1, at 3; NEGWA-MM-1, at 3).

2. Positions of the Parties

a. NEGWA

NEGWA asserts that National Grid's soft disconnect policy invites unauthorized users to consume large quantities of gas without payment (NEGWA Brief at 12, citing Exh. NEGWA-MM-1, at 3). NEGWA asserts that the resulting loss in revenue is ultimately passed on to ratepayers (NEGWA Brief at 12, citing Exh. NEGWA-MM-1, at 3). NEGWA recommends limiting the use of a soft disconnect to a 30-day period (Exh. NEGWA-MM-1, at 4).

b. National Grid

The Companies assert that in most instances, the change in customer accounts is temporary and that leaving the supply of gas physically uninterrupted provides greater customer convenience and satisfaction as it avoids the need for the customer to schedule multiple service visits (National Grid Brief at IV.36). National Grid asserts that its soft disconnect policy is widely followed in the industry and also serves to reduce the cost of service (National Grid Brief at IV.36). National Grid further asserts that it has controls in place to monitor such accounts to ensure the practice cannot be abused (National Grid Brief at IV.36).

3. Analysis and Findings

Both NEGWA and National Grid agree that for situations where the change in customer accounts is limited to a short period of time, e.g., 30 days, it is reasonable that the Companies would undertake a soft disconnect (see Exhs. NG-WJA/JBH-Rebuttal-1, at 3; NEGWA-MM-1,a t 3-4; Tr. 18, at 2539). We agree that using soft disconnects in these limited circumstances may reduce costs by eliminating field trips as well as increase customer service satisfaction because customers do not have to remain at home to provide access to the location (Exh. NG-WJA/JBH-Rebuttal-1, at 3-4).

Nonetheless, the Department is concerned that there may be situations where a soft disconnect is used for a period of time that exceeds 30 days. Thus, we direct the Companies to ensure that they have the appropriate practice in place so that soft disconnects are only used for those changes in service that are less than 30 days. The Companies should file a report with the Department within 30 days of issuance of this Order outlining the process they have in place to ensure that physical shut-offs are used for changes in service that exceed 30 days.

XIV. SCHEDULES

SCHEDULE 1 - BOSTON GAS/ESSEX GAS				
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	891,025,628	(433,706)	(3,442,603)	887,149,318
Depreciation	90,277,000	(1,886)	(820,748)	89,454,366
Amortization	8,598,000	(1,890,120)	0	6,707,880
Taxes Other Than Income Taxes	33,834,463	570,907	0	34,405,370
Income Taxes	38,077,311	271,742	(11,101,717)	27,247,336
Interest on Customer Deposits	27,360	0	0	27,360
Return on Rate Base	94,924,171	25,010	(17,200,939)	77,748,243
Total Cost of Service	1,156,763,933	(1,458,053)	(32,566,007)	1,122,739,873
OPERATING REVENUES				
Operating Revenues	1,174,030,509	0	0	1,174,030,509
Revenue Adjustments*	(96,543,859)	0	3,801,385	(92,742,474)
Total Operating Revenues	1,077,486,650	0	3,801,385	1,081,288,035
Total Base Revenue Deficiency	**79,277,283**	**(1,458,053)**	**(36,367,392)**	**41,451,838**
				79,277,283
				41,451,838
			DECREASE	**37,825,445**
			BAD DEBT	1.0182
				38,513,868
			BAD DEBT DECREASE	(688,423)

SCHEDULE 2 - BOSTON GAS/ESSEX GAS				
OPERATIONS AND MAINTENANCE EXPENSES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Purchased Gas Expense	740,602,504	0	0	740,602,504
Total Adj. to Purchased Gas Expense	(124,786,413)	0	0	(124,786,413)
Total Purchased Gas Expense	615,816,091	0	0	615,816,091
Test Year Distribution O&M Expense	237,252,026	0	0	237,252,026
ADJUSTMENTS TO O&M EXPENSE:				
Labor	888,487	0	0	888,487
Health & Hospitalization	(1,195,351)	0	0	(1,195,351)
Computer Software	301,132	(512,633)	0	(211,501)
DPU Assessment Fees	(880,593)	0	0	(880,593)
Facilities	644,168	836,432	(78,088)	1,402,512
Insurance Claims	2,070,846	1	0	2,070,847
Insurance Premiums	374,688	1,800	0	376,488
Inside Service Inspections	748,000	0	(343,421)	404,579
Payroll Taxes	(28,881)	1	0	(28,880)
PBOPs	1,812,720	0	0	1,812,720
PBOP Deferral Amoritzation	(1,323,461)	0	0	(1,323,461)
Pensions	8,792,425	0	0	8,792,425
Pension Deferral Amorization	784,837	0	0	784,837
Postage	214,770	0	(30,254)	184,516
Boston Water Main Break	743,391	(51,778)	(691,613)	0
Strike Contingency Costs	541,803	(35,749)	(20,026)	486,028
Rate Case Expense	346,368	97,498	(123,329)	320,537
Uncollectables Commodity (Bad Debt)	18,353,726	0	0	18,353,726
Uncollectables Distribution (Bad Debt)	(8,065,939)	0	(17,588)	(8,083,527)
Distrigas	(325,476)	0	0	(325,476)
LNG Production and Storage	14,041,647	0	0	14,041,647
Inflation	(2,905,397)	(9,097)	(47,118)	(2,961,612)
Leases: Officer Vehicles	0	0	(11,280)	(11,280)
Expatriate, Officer, Director Expenses	0	(722,943)	0	(722,943)
Drivecam	0	0	(143,368)	(143,368)
Employee Reimbursements	0	0	(9,789)	(9,789)
Promotional Programs	0	0	(638,175)	(638,175)
Advertising Expense	0	0	(359,214)	(359,214)
Total Other O&M Expenses	35,933,910	(396,467)	(2,513,263)	33,024,180
Total Distribution O&M Expense	**273,185,936**	**(396,467)**	**(2,513,263)**	**270,276,206**
Uncollectibles on Proposed Rate Increase	2,023,601	(37,239)	(929,340)	1,057,022
Total O&M Expense	**891,025,628**	**(433,706)**	**(3,442,603)**	**887,149,318**
	4,484,063			
	(2,905,397)			
	1,578,666			

SCHEDULE 3 - BOSTON GAS/ESSEX GAS					
DEPRECIATION AND AMORTIZATION EXPENSES					
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER	
Depreciation Expense	90,277,000	(1,886)	(820,748)	89,454,366	0
Amortization Expense	8,598,000	(1,890,120)	0	6,707,880	0
Total Depreciation & Amortization Expenses	**98,875,000**	**(1,892,006)**	**(820,748)**	**96,162,246**	0

SCHEDULE 4 - BOSTON GAS/ESSEX GAS				
RATE BASE AND RETURN ON RATE BASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	2,178,375,238	(67,851)	(20,440,786)	2,157,866,601
LESS:				
Reserve for Depreciation and Amortlization	(880,557,792)	836	9,158,423	(871,398,533)
Net Utility Plant in Service	1,297,817,446	(67,015)	(11,282,363)	1,286,468,068
ADDITIONS TO PLANT:				
Prepayments	190,398	0	(190,398)	0
Heel Gas Inventory - Storage	2,546,204	0	0	2,546,204
Heel Gas Inventory - LNG	3,242,128	0	0	3,242,128
Cash Working Capital	21,951,521	15,403	(3,530,029)	18,436,895
Materials and Supplies	4,513,021	0	0	4,513,021
Total Additions to Plant	32,443,272	15,403	(3,720,427)	28,738,248
DEDUCTIONS FROM PLANT:				
Plant Held for Future Use	(515,704)	0	0	(515,704)
Work in Progress	(14,012,817)	0	0	(14,012,817)
Reserve for Deferred Income Tax	(255,307,044)	0	2,809,263	(252,497,781)
Amortization of Intangible Plant	(74,604,887)	0	0	(74,604,887)
Unamortized ITC-Pre1971	(310,515)	310,515	0	0
Customer Contribution	(2,849,998)	0	0	(2,849,998)
Customer Advances	(7,875)	0	0	(7,875)
Total Deductions from Plant	(347,608,840)	310,515	2,809,263	(344,489,062)
RATE BASE	982,651,878	258,903		982,910,781
COST OF CAPITAL	9.66%	9.66%	7.91%	7.91%
RETURN ON RATE BASE	**94,924,171**	**25,010**	**(17,200,939)**	**77,748,243**

SCHEDULE 5 - BOSTON GAS/ESSEX GAS

COST OF CAPITAL

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$583,000,000	46.36%	7.76%	3.60%
Preferred Stock		0.00%	0.00%	0.00%
Common Equity	$674,431,797	53.64%	11.30%	6.06%
Total Capital	$1,257,431,797	100.00%		9.66%
Weighted Cost of				
Debt				3.60%
Equity				6.06%
Cost of Capital				9.66%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$583,000,000	46.36%	7.76%	3.60%
Preferred Stock		0.00%	0.00%	0.00%
Common Equity	$674,431,797	53.64%	11.30%	6.06%
Total Capital	$1,257,431,797	100.00%		9.66%
Weighted Cost of				
Debt				3.60%
Equity				6.06%
Cost of Capital				9.66%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$428,715,899	50.00%	6.07%	3.03%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$428,715,899	50.00%	9.75%	4.88%
Total Capital	$857,431,798	100.00%		7.91%
Weighted Cost of				
Debt				3.03%
Equity				4.88%
Cost of Capital				7.91%

SCHEDULE 6 - BOSTON GAS/ESSEX GAS				
CASH WORKING CAPITAL				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Other O&M Expense	273,185,936	(396,467)	(2,513,263)	270,276,206
Uncollectables on Proposed Rate Increase	0	0	1,057,022	1,057,022
LESS:				
PBOPs	9,999,556	0	0	9,999,556
PBOP Deferral Amoritzation	1,925,571	0	0	1,925,571
PBOP Transition Obligation	2,711,283	0	0	2,711,283
Pensions	19,782,783	0	0	19,782,783
Pension Deferral Amoritzation	5,649,745	0	0	5,649,745
Uncollectibles - Commodity (Bad Debt)	18,353,726	0	0	18,353,726
Subtotal - O&M Expense	214,763,272	(396,467)	(1,456,241)	212,910,563
Other Taxes ex. Property Taxes	7,981,799	0	0	7,981,799
Property Taxes	25,852,664	570,907	0	26,423,571
Amount Subject to Cash Working Capital	248,597,735	174,440	(1,456,241)	247,315,933
Lead/Lag Factor	0.08830	0	(0.01375)	0.07455
Total Cash Working Capital Allowance	**21,951,521**	**15,403**	**(3,530,029)**	**18,436,895**
*Per Company Composite Total times (43.85 / 365	12.014%			
** Per DPU Composite Total times (43.0 / 365)	11.781%			

SCHEDULE 7 - BOSTON GAS/ESSEX GAS				
TAXES OTHER THAN INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA Taxes	5,666,253	0	0	5,666,253
Property Taxes	25,852,664	570,907	0	26,423,571
Other State	2,315,546	0	0	2,315,546
Total Taxes Other Than Income Taxes	**33,834,463**	**570,907**	**0**	**34,405,370**

SCHEDULE 8 - BOSTON GAS/ESSEX GAS				
INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	982,651,878	258,903	0	982,910,781
Return on Rate Base	94,924,171	25,010	(17,200,939)	77,748,243
LESS:				
Interest Expense	35,381,153	(31,810)	0	35,349,343
Total Deductions	35,381,153	(31,810)	0	35,349,343
Amortization of Investment Tax Credit	(214,263)	142,863	0	(71,400)
Amortization of Excess Deferred Incomes Taxes	0	0	0	0
Taxable Income Base	59,328,755	199,683	(17,200,939)	42,327,500
Gross Up Factor	1.6454134	1.6454134	1.6454134	1.6454134
Taxable Income	97,620,329	328,564	(28,302,657)	69,646,236
Mass Franchise Tax	6,345,321	21,357	(1,839,673)	4,527,005
6.50%				
Federal Taxable Income	91,275,008	307,207	(26,462,984)	65,119,231
Federal Income Tax Calculated	31,946,253	107,522	(9,262,044)	22,791,731
Total Income Taxes Calculated	38,291,574	128,879	(11,101,717)	27,318,736
Amortization of Investment Tax Credit	(214,263)	142,863	0	(71,400)
Total Income Taxes	**38,077,311**	**271,742**	**(11,101,717)**	**27,247,336**

SCHEDULE 9 - BOSTON GAS/ESSEX GAS				
REVENUES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	1,174,030,509	0	0	1,174,030,509
Revenue Adjustments				
Billed Sales - Firm Tariff	4,044,241	0	0	4,044,241
Unbilled Sales	(6,318,187)	0	0	(6,318,187)
Broker Revenues	(3,776,237)	0	0	(3,776,237)
Customer Adjustments	483,967	0	0	483,967
Reconnect Fees	(9,262)	0	0	(9,262)
DSM Incentive	(1,197,873)	0	0	(1,197,873)
Optimization & Other Off System Sales	(89,770,508)	0	0	(89,770,508)
Special Contracts	0	0	3,801,385	3,801,385
Total Revenue Adjustments	(96,543,859)	0	3,801,385	(92,742,474)
Adjusted Total Operating Revenues	**1,077,486,650**	**0**	**3,801,385**	**1,081,288,035**

SCHEDULE 10
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE BY SERVICE
BOSTON GAS

	PER ORDER TOTAL	DISTRIBUTION SERVICE*	GAS SERVICE*		AS FILED TOTAL COMPANY	DISTRIBUTION SERVICE PER COMPANY	GAS SERVICE PER COMPANY
Cost of Gas	615,816,091	0	615,816,091		615,816,091	0	615,816,091
O&M Expense	271,333,228	208,883,710	62,449,518		275,209,539	211,867,857	63,341,682
Operations Expenses	887,149,319	210,946,149	676,203,170		891,025,630	211,867,857	679,157,773
Uncollectible O&M Due to Increase	0	0	0		0	0	0
Depreciation Expense	89,454,366	87,045,682	2,408,684		90,276,999	87,846,164	2,430,835
Amortization Expense	6,707,880	6,541,721	166,159		8,598,000	8,385,022	212,978
Taxes Other Than Income Taxes	34,405,370	33,466,519	938,851		33,834,463	32,911,191	923,272
Income Taxes	27,247,336	26,568,606	678,730		38,059,700	37,111,634	948,066
Interest on Customer Deposits	27,360	27,360	0		27,360	27,360	0
Amortization of ITC	0	0	0		0	0	0
Rate Base	982,910,781	958,563,452	24,347,330		982,651,878	958,310,962	24,340,917
Rate of Return	7.91%	7.91%	7.91%		9.66%	9.66%	9.66%
Return on Rate Base	77,748,243	75,822,369	1,925,874		94,896,883	92,546,227	2,350,657
Cost of Service	1,122,739,874	440,418,406	682,321,468		1,156,719,035	470,695,455	686,023,581
Revenues Credited to Cost of Service	(21,640,610)	(21,640,610)	0		(21,640,610)	(21,640,610)	0
Total Cost of Service	**1,101,099,264**	**418,777,796**	**682,321,468**		**1,135,078,425**	**449,054,845**	**686,023,581**
Operating Revenues - per books	1,174,030,509	499,516,998	674,513,511		1,174,030,509	499,516,998	674,513,511
Revenues Transferred to Cost of Service	(21,640,610)	(21,640,610)	0		(21,640,610)	(21,640,610)	0
Revenue Adjustments	(92,742,474)	(92,742,474)	0		(96,543,859)	(96,543,859)	0
Total Operating Revenues	**1,059,647,425**	382,705,449	676,941,976		**1,055,846,040**	**381,332,529**	**674,513,511**
Revenue Deficiency	**41,451,839**	**36,072,347**	**5,379,492**		**79,232,385**	**67,722,316**	**11,510,070**

* The Department has estimated the values in these columns using the ratios derived from the "Distribution Service per Company" and "Gas Service per Company" columns to the "Total Company as filed" column. The actual values for these columns will be known when the Company re-runs its Cost of Service Study.

THIS SCHEDULE IS FOR ILLUSTRATIVE PURPOSES ONLY

SCHEDULE 11 – BOSTON GAS/ESSEX GAS

RATE CLASS	AS FILED TEST YEAR BASE REVENUES	AS FILED TEST YEAR GAF REVENUES	ASFILED TEST YEAR LDAF REVENUES	AS FILED TEST YEAR TOTAL REVENUES	PROPOSED TARGET REVENUE INCREASE AT EROR	PROPOSED % INCREASE AT EROR	PER ORDER TARGET BASE REVENUE INCREASE AT EROR	PER ORDER REVENUE INCREASE AT 110% CAP	PER ORDER REVENUE TO BE REALLOCATE	PER ORDER REVENUES FOR REALLOCAT	PER ORDER REVENUE TO BE REALLOCATED	PER ORDER % INCREASE TOT REVENUES AT EROR	TARGET BASE REVENUE INCREASE	TARGET BASE REVENUE REQUIREMENT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
BOSTON GAS														
RESIDENTIAL														
NONHEAT (R-1 & R-2)	$24,849,552	$18,559,937	$2,213,183	$45,622,672	$1,824,359	3.92%	$971,739	$1,615,939	$0	$300,830	$1,377,901	2.96%	$1,272,570	$26,211,588
HEAT (R-3 & R-4)	$210,318,287	$401,567,939	$43,960,044	$655,846,270	$36,894,806	5.54%	$19,651,909	$23,141,457	$0	$741,810	$22,554,484	3.38%	$20,393,719	$231,469,219
COMMERCIAL (LLF)														
G/T-41	$18,046,628	$28,162,293	$2,197,015	$48,405,936	-$1,265,018	-2.61%	-$673,808	$1,680,578	$0	$1,231,719	$705,955	1.46%	$557,911	$18,669,512
G/T-42	$16,487,912	$42,514,871	$3,362,591	$62,365,374	$2,873,014	4.61%	$1,530,302	$2,165,228	$0	$228,646	$1,984,307	3.18%	$1,758,948	$18,306,222
G/T-43	$36,438,432	$124,108,570	$9,892,137	$170,439,139	$9,627,265	5.65%	$5,127,934	$5,917,380	$0	$71,728	$5,860,623	3.44%	$5,199,662	$41,769,284
G/T-44	$14,275,036	$55,093,524	$4,631,305	$73,999,865	$3,021,698	4.08%	$1,609,498	$2,569,159	$0	$471,143	$2,196,358	2.97%	$2,080,641	$16,407,072
COMMERCIAL (HLF)														
G/T-51	$6,214,010	$11,232,639	$974,694	$18,421,343	-$638,063	-3.46%	-$339,862	$639,560	$0	$511,576	$234,765	1.27%	$171,714	$6,408,097
G/T-52	$6,874,900	$19,160,063	$1,681,165	$27,716,128	$128,888	0.47%	$68,652	$962,261	$0	$438,407	$615,362	2.22%	$507,058	$7,406,710
G/T-53	$9,441,783	$31,850,767	$2,753,216	$44,045,766	$660,254	1.50%	$351,682	$1,529,200	$0	$557,797	$1,087,832	2.47%	$909,479	$10,385,256
G/T-54	$9,906,517	$46,580,935	$4,276,713	$60,764,165	$1,830,207	3.01%	$974,854	$2,109,637	$0	$552,567	$1,672,406	2.75%	$1,527,421	$11,469,605
GAS STREET LIGHTS (L)														
G-07	$522,801	$925,397	$84,313	$1,532,511	-$344,454	-22.48%	-$183,472	$71,349	-$249,464	$0	$71,349	4.66%	$65,991	$590,674
G-17	$23,419	$9,193	$820	$33,432	-$21,608	-64.63%	-$11,509	-$5,736	-$5,695	$0	-$5,736	-17.16%	-$5,815	$17,689
TOTAL BOSTON	$353,399,277	$779,766,128	$76,027,196	$1,209,192,601	$54,591,348	4.47%	$29,077,919	$42,396,012	-$255,158	$5,106,223	$38,355,606	3.14%	$34,439,300	$389,110,928
ESSEX GAS														
RESIDENTIAL														
NONHEAT (R-1 & R-2)	$1,280,816	$896,129	$84,932	$2,261,877	$365,218	15.86%	$194,542	$79,971	$141,853	$0	$79,971	3.47%	$52,689	$1,338,116
HEAT (R-3 & R-4)	$18,695,137	$37,106,095	$3,181,397	$58,982,629	$11,146,470	18.57%	$5,937,428	$2,083,390	$4,754,570	$0	$2,083,390	3.47%	$1,182,857	$19,945,303
COMMERCIAL (LLF)														
G/T-41	$3,230,053	$7,871,769	$430,006	$11,531,828	$1,443,244	12.52%	$768,778	$400,367	$547,554	$0	$400,367	3.47%	$221,223	$3,462,906
G/T-42	$1,472,482	$4,652,784	$256,424	$6,381,690	$245,985	3.85%	$131,029	$221,562	$17,714	$0	$221,562	3.47%	$113,315	$1,591,099
G/T-43	$412,821	$1,297,986	$70,624	$1,781,431	$103,994	5.84%	$55,395	$61,848	$22,793	$0	$61,848	3.47%	$32,602	$446,909
G/T-44														
COMMERCIAL (HLF)														
G/T-51	$1,588,624	$3,911,636	$235,141	$5,735,401	$208,779	3.64%	$111,211	$199,124	$23,526	$0	$199,124	3.47%	$87,685	$1,682,029
G/T-52	$911,133	$2,567,800	$161,831	$3,640,764	-$225,575	-6.20%	-$120,158	$126,402	$0	$92,448	$53,250	1.46%	-$27,710	$886,703
G/T-53	$342,185	$748,429	$49,788	$1,140,402	-$157,313	-13.79%	-$83,797	$39,593	$0	$54,182	-$3,280	-0.29%	-$29,614	$313,803
TOTAL ESSEX	$27,933,252	$59,052,628	$4,470,144	$91,456,023	$13,130,801	14.19%	$6,994,428	$3,212,257	$5,508,011	$146,630	$3,096,233	3.35%	$1,633,047	$29,666,868
TOTAL BOSTON+ESSEX	$381,332,529	$838,818,756	$80,497,340	$1,300,648,624	$67,722,149	5.16%	$36,072,347	$45,608,269	$5,252,853	$5,252,853	$41,451,839	3.16%	36,072,347	418,777,796

Note: Schedule 11 is for illustrative purposes only.

(A) Exh. NG-JDS-2-3-BGC, at 19,20 and 22, Line 142
(B) Exh. NG-JDS-2-3-BGC, at 1, 2 and 4, Line 39
(C) Exh. NG-JDS-2-3-BGC, at 1, 2 and 4,Line 27

SCHEDULE 1 - COLONIAL GAS				
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	242,306,029	(1,354,816)	(3,564,731)	237,386,482
Depreciation	19,570,664	(1,842)	0	19,568,822
Amortization	1,374,492	(108,492)	(29,733)	1,236,267
Taxes Other Than Income Taxes	6,012,128	361,135	0	6,373,263
Income Taxes	9,615,838	283,067	(2,352,162)	7,546,744
Interest on Customer Deposits	4,277	0	0	4,277
Return on Rate Base	23,442,535	78,876	(3,652,677)	19,868,735
Total Cost of Service	302,325,963	(742,071)	(9,599,302)	291,984,590
OPERATING REVENUES				
Operating Revenues	286,829,262	0	0	286,829,262
Revenue Adjustments*	(11,314,358)	(8,529)	3,186	(11,319,701)
Total Operating Revenues	275,514,904	(8,529)	3,186	275,509,561
Total Base Revenue Deficiency	**26,811,059**	**(733,542)**	**(9,602,488)**	**16,475,029**
				26,811,059
				16,475,029
			DECREASE	**10,336,031**
			BAD DEBT	1.0182
				10,524,146
			BAD DEBT DECREASE	(188,116)

SCHEDULE 2 - COLONIAL GAS OPERATIONS AND MAINTENANCE EXPENSES	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Purchased Gas Expense	193,385,833	0	0	193,385,833
Total Adj. to Purchased Gas Expense	(15,737,391)	0	0	(15,737,391)
Total Purchased Gas Expense	177,648,442	0	0	177,648,442
Test Year Distribution O&M Expense	47,493,049	0	0	47,493,049
ADJUSTMENTS TO O&M EXPENSE:				
Labor	777,977	0	0	777,977
Health & Hospitalization	(564,049)	0	0	(564,049)
Computer Software	39,785	(93,050)	0	(53,265)
DPU Assessment Fees	(215,772)	0	0	(215,772)
Facilities	197,461	137,144	(31,411)	303,194
Insurance Claims	94,944	0	0	94,944
Insurance Premiums	56,526	419	0	56,945
Inside Service Inspections	30,000	0	(10,909)	19,091
Payroll Taxes	(12,681)	23,166	0	10,485
PBOPs	46,873	0	0	46,873
Pensions	(221,621)	0	0	(221,621)
Postage	54,082	0	(8,782)	45,300
Merger-Related Costs	12,300,000	(1,425,143)	(3,048,669)	7,826,188
Strike Contingency Costs	0	35,749	(1,374)	34,375
Rate Case Expense	179,448	61,527	(64,839)	176,136
Uncollectables Commodity (Bad Debt)	3,365,809	0	0	3,365,809
Uncollectables Distribution (Bad Debt)	(2,492,315)	0	(781)	(2,493,096)
LNG Production and Storage	3,311,863	0	0	3,311,863
Inflation	(271,971)	(3,092)	(7,854)	(282,917)
Leases: Officer Vehicles	0	0	(2,412)	(2,412)
Expatriate, Officer, Director Expenses	0	(82,161)	0	(82,161)
Drivecam	0	0	(27,290)	(27,290)
Employee Reimbursements	0	0	(2,075)	(2,075)
Promotional Programs	0	0	(103,181)	(103,181)
Advertising Expense	0	0	(76,196)	(76,196)
Sum of O&M Expense Adjustments	16,676,359	(1,345,441)	(3,385,773)	11,945,145
Total Distribution O&M Expense	64,169,408	(1,345,441)	(3,385,773)	59,438,194
Uncollectables on Proposed Rate Increase	488,179	(9,375)	(178,958)	299,846
Total O&M Expense	242,306,029	(1,354,816)	(3,564,731)	237,386,482

SCHEDULE 3 - COLONIAL GAS				
DEPRECIATION AND AMORTIZATION EXPENSES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation Expense	19,570,664	(1,842)	0	19,568,822
Amortization Expense	1,374,492	(108,492)	(29,733)	1,236,267
Total Depreciation & Amortization Expenses	**20,945,156**	**(110,334)**	**(29,733)**	**20,805,089**

SCHEDULE 4 - COLONIAL GAS				
RATE BASE AND RETURN ON RATE BASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	586,968,290	(31,220)	0	586,937,070
LESS:				
Reserve for Depreciation and Amortlization	245,234,937	0	0	245,234,937
Net Utility Plant in Service	341,733,353	(31,220)	0	341,702,133
ADDITIONS TO PLANT:				
Cash Working Capital	2,703,043	(62,226)	(124,742)	2,516,075
Materials and Supplies	571,269	0	0	571,269
Prepayments	126,391	0	(126,391)	0
Heel Gas Inventory	1,588,180	0	0	1,588,180
Total Additions to Plant	4,988,883	(62,226)	(251,133)	3,087,344
DEDUCTIONS FROM PLANT:				
Work in Progress	(2,310,503)	0	0	(2,310,503)
Reserve for Deferred Income Tax	(90,698,563)	0	0	(90,698,563)
Amortization of Intangible Plant	(9,400,680)	0	0	(9,400,680)
Unamoritized ITC-Pre-1971	(910,817)	910,817	0	0
Customer Contributions	(33,021)	0	0	(33,021)
Customer Deposits	(445,491)	0	0	(445,491)
Total Deductions from Plant	(103,799,075)	910,817	0	(102,888,258)
RATE BASE	242,923,161	817,371	(251,133)	243,489,399
COST OF CAPITAL	9.65%	9.65%	-1.49%	8.16%
RETURN ON RATE BASE	23,442,535	78,876	(3,652,677)	19,868,735

SCHEDULE 5 - COLONIAL GAS

COST OF CAPITAL

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$124,000,000	46.04%	7.72%	3.55%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$145,306,000	53.96%	11.30%	6.10%
Total Capital	$269,306,000	100.00%		9.65%
Weighted Cost of				
Debt				3.55%
Equity				6.10%
Cost of Capital				9.65%
	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$124,000,000	46.04%	7.72%	3.55%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$145,306,000	53.96%	11.30%	6.10%
Total Capital	$269,306,000	100.00%		9.65%
Weighted Cost of				
Debt				3.55%
Equity				6.10%
Cost of Capital				9.65%
	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$110,153,178	50.00%	6.57%	3.29%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$110,153,178	50.00%	9.75%	4.88%
Total Capital	$220,306,356	100.00%		8.16%
Weighted Cost of				
Debt				3.29%
Equity				4.88%
Cost of Capital				**8.16%**

SCHEDULE 6 - COLONIAL GAS				
CASH WORKING CAPITAL				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Other O&M Expense	64,169,408	(1,345,441)	(3,385,773)	59,438,194
Uncollectables on Proposed Rate Increase	0	0	299,846	299,846
LESS:				
PBOP	1,937,343	0	0	1,937,343
Pension	6,280,369	0	0	6,280,369
Merger-Relatex Expenses	12,300,000	0	0	12,300,000
Uncollectables - Commodity	3,365,809	0	0	3,365,809
Subtotal - O&M Expenses	40,285,887	(1,345,441)	(3,385,773)	35,554,673
Other Taxes ex. Property Taxes	1,300,460	0	0	1,300,460
Property Taxes	4,711,668	279,631	0	4,991,299
Amount Subject to Cash Working Capital	46,298,015	(1,065,810)	(3,085,927)	42,146,278
Lead/Lag Factor	0.05838	0	0.00132	0.05970
Total Cash Working Capital Allowance	**2,703,043**	**(62,226)**	**(124,742)**	**2,516,075**
*Per Company Composite Total times (43.85 / 365	12.329%			
** Per DPU Composite Total times (43.0 / 365)	11.781%			

SCHEDULE 7 - COLONIAL GAS				
TAXES OTHER THAN INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA Taxes	1,035,432	81,504	0	1,116,936
Other State Taxes	265,028	0	0	265,028
Property Taxes	4,711,668	279,631	0	4,991,299
Total Taxes Other Than Income Taxes	**6,012,128**	**361,135**	**0**	**6,373,263**

SCHEDULE 8 - COLONIAL GAS				
INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	242,923,161	817,371	(251,133)	243,489,399
Return on Rate Base	23,442,535	78,876	(3,652,677)	19,868,735
LESS:				
Interest Expense	8,631,518	29,043	(8,250)	8,652,311
Amoritzation of ITC	(355,803)	152,487	0	(203,316)
Amortization of Excess Deferred Incomes Taxes	390,207	0	0	390,207
Total Deductions	8,665,922	181,530	(8,250)	8,839,202
Taxable Income Base	14,845,421	202,321	(3,644,427)	11,029,533
Gross Up Factor	1.6454134	1.6454134	1.6454134	1.6454134
Taxable Income	24,426,855	332,901	(5,996,589)	18,763,167
Mass Franchise Tax	1,587,746	21,639	(389,778)	1,219,607
6.50%				
Federal Taxable Income	22,839,109	311,262	(5,606,811)	17,543,560
Federal Income Tax Calculated	7,993,688	108,942	(1,962,384)	6,140,246
Total Income Taxes Calculated	9,581,434			9,581,434
Amortization of Excess Deferred Incomes Taxes	390,207	130,580	(2,352,162)	(1,831,374)
Amortization of Investment Tax Credit	(355,803)	152,487	0	(203,316)
Total Income Taxes	**9,615,838**	**283,067**	**(2,352,162)**	**7,546,744**
	19,915,878			7,546,744
	9,615,838			19,746,887
	10,300,040			(12,200,143)

SCHEDULE 9 - COLONIAL GAS				
REVENUES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	286,829,262	0	0	286,829,262
Revenue Adjustments				
Billed Sales - Firm Tariff	1,250	0	0	1,250
Unbilled Sales	(1,077,071)	0	0	(1,077,071)
Broker Revenues	(904,251)	0	0	(904,251)
Customer Adjustments	316,015	0	0	316,015
Reconnect Fees	(53,420)	0	0	(53,420)
Bad Check Fees	30,130	0	0	30,130
Lost Margin	(657,595)	0	0	(657,595)
DSM Incentive	(333,256)	0	0	(333,256)
Optimization & Other Off System Sales	(8,636,160)	(8,529)	0	(8,644,689)
Special Contracts	0	0	3,186	3,186
Total Revenue Adjustments	(11,314,358)	(8,529)	3,186	(11,319,701)
Adjusted Total Operating Revenues	**275,514,904**	**(8,529)**	**3,186**	**275,509,561**

SCHEDULE 10
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE BY SERVICE
COLONIAL GAS

	PER ORDER TOTAL	DISTRIBUTION SERVICE*	GAS SERVICE*		AS FILED TOTAL COMPANY	DISTRIBUTION SERVICE PER COMPANY	GAS SERVICE PER COMPANY
Cost of Gas	177,648,442	0	177,648,442		177,648,442	0	177,648,442
O&M Expense	59,738,040	46,494,830	13,243,210		64,657,589	50,323,774	14,333,815
Operations Expenses	237,386,482	49,302,048	188,084,434		242,306,031	50,323,774	191,982,257
Uncollectible O&M Due to Increase	0	0	0		0	0	0
Depreciation Expense	19,568,822	18,629,397	939,425		19,570,664	18,631,151	939,513
Amortization Expense	1,236,267	1,236,267	0		1,374,492	1,374,492	0
Taxes Other Than Income Taxes	6,373,263	6,013,178	360,085		6,012,128	5,672,447	339,681
Income Taxes	7,546,744	7,052,006	494,738		9,615,837	8,985,457	630,380
Interest on Customer Deposits	4,277	4,277	0		4,277	4,277	0
Amortization of ITC	0	0	0		0	0	0
Rate Base	243,489,399	227,469,569	16,019,830		242,923,161	226,940,585	15,982,576
Rate of Return	8.16%	8.16%	8.16%		9.65%	9.65%	9.65%
Return on Rate Base	19,868,735	18,561,517	1,307,218		23,442,536	21,900,187	1,542,348
Cost of Service	291,984,590	100,798,691	191,185,899		302,325,965	106,891,785	195,434,179
Revenues Credited to Cost of Service	(888,952)	(888,952)	0		(888,952)	(888,952)	0
Total Cost of Service	**291,095,638**	**99,909,739**	**191,185,899**		**301,437,013**	**106,002,833**	**195,434,179**
Operating Revenues - per books	286,829,262	103,063,672	183,765,590		286,829,262	103,063,672	183,765,590
Revenues Transferred to Cost of Service	(888,952)	(888,952)	0		(888,952)	(888,952)	0
Revenue Adjustments	(11,319,701)	(11,319,701)	0		(11,314,358)	(11,314,358)	0
Total Operating Revenues	**274,620,609**	**90,855,019**	**183,765,590**		**274,625,952**	**90,860,362**	**183,765,590**
Revenue Deficiency	16,475,029	9,054,720	7,420,309		26,811,061	15,142,471	11,668,589

* The Department has estimated the values in these columns using the ratios derived from the "Distribution Service per Company" and "Gas Service per Company" columns to the "Total Company as filed" column. The actual values for these columns will be known when the Company re-runs its Cost of Service Study.

THIS SCHEDULE IS FOR ILLUSTRATIVE PURPOSES ONLY

SCHEDULE 11 – COLONIAL GAS

RATE CLASS	AS FILED TEST YEAR BASE REVENUES (A)	AS FILED TEST YEAR GAF REVENUES (B)	ASFILED TEST YEAR LDAF REVENUES (C)	AS FILED TEST YEAR TOTAL REVENUES (D)	TEST YEAR LOW INCOM (E)	TEST YEAR TOTAL rEVENUES w/ LI DISCOUN (F)	PROPOSED TARGET BAS REVENUE AT EROR (G)	PROPOSED TARGET REVENUE INCREASE AT EROR (H)	PROPOSED % INCREAS TOT REVEN AT EROR (I)	PER ORDER TARGET BAS REVENUE INCREASE AT EROR (J)	PER ORDER TOTAL REVENUE INCREASE W/O CAP (K)
COL GAS											
RESIDENTIAL											
NONHEAT (R-1 & R-2)	$1,906,135	$1,290,092	$102,292	$3,298,519	$5,057	$3,303,576	$1,773,268	-$132,867	-4.02%	-$132,867	-$58,391
HEAT (R-3 & R-4)	$34,580,918	$64,136,254	$4,580,241	$103,297,413	$1,040,869	$104,338,282	$40,181,966	$5,601,048	5.37%	$5,601,047	$8,984,703
COMMERCIAL (LLF)											
G/T-41	$4,878,877	$9,642,103	$405,077	$14,926,057	$0	$14,926,057	$5,066,927	$188,050	1.26%	$188,050	$664,038
G/T-42	$1,290,518	$4,251,955	$182,847	$5,725,320	$0	$5,725,320	$1,524,207	$233,689	4.08%	$233,689	$447,051
G/T-43	$276,450	$905,775	$39,001	$1,221,226	$0	$1,221,226	$308,208	$31,758	2.60%	$31,758	$77,119
COMMERCIAL (HLF)											
G/T-51	$2,083,715	$5,449,487	$268,681	$7,801,883	$0	$7,801,883	$2,050,602	-$33,113	-0.42%	-$33,113	$274,866
G/T-52	$1,172,231	$4,046,177	$190,899	$5,409,307	$0	$5,409,307	$1,240,550	$68,319	1.26%	$68,319	$288,641
G/T-53	$1,456,479	$6,499,349	$313,797	$8,269,625	$0	$8,269,625	$1,684,745	$228,266	2.76%	$228,266	$588,898
GAS STREET LIGHTS (L)											
G-17	$3,783	$10,830	$540	$15,153	$0	$15,153	$2,655	-$1,128	-7.44%	-$1,128	-$514
TOTAL CAPE	$47,649,106	$96,232,022	$6,083,375	$149,964,503	$1,045,926	$151,010,429	$53,833,128	$6,184,022	4.10%	$6,184,021	$11,266,411
LOWELL											
CAPE DIVISION											
RESIDENTIAL											
NONHEAT (R-1 & R-2)	$650,235	$610,670	$50,435	$1,311,340	$27,077	$1,338,417	$1,077,377	$427,142	31.91%	$427,142	$461,160
HEAT (R-3 & R-4)	$28,787,437	$65,806,540	$5,050,840	$99,644,817	$1,705,990	$101,350,807	$38,298,689	$9,511,252	9.38%	$9,511,254	$12,724,976
COMMERCIAL (LLF)											
G/T-41	$4,719,967	$15,018,584	$709,392	$20,447,943	$0	$20,447,943	$6,271,627	$1,551,660	7.59%	$1,551,660	$2,212,359
G/T-42	$2,502,090	$10,216,466	$486,756	$13,205,312	$0	$13,205,312	$2,223,477	-$278,613	-2.11%	-$278,613	$179,093
G/T-43	$1,098,859	$5,196,596	$252,978	$6,548,433	$0	$6,548,433	$654,940	-$443,919	-6.78%	-$443,919	-$200,822
G/T-44											
COMMERCIAL (HLF)											
G/T-51	$1,479,884	$4,864,178	$258,399	$6,602,461	$0	$6,602,461	$1,927,709	$447,825	6.78%	$447,825	$713,553
G/T-52	$1,234,923	$5,050,175	$266,553	$6,551,651	$0	$6,551,651	$974,299	-$260,624	-3.98%	-$260,624	$12,434
G/T-53	$2,737,862	$14,184,376	$789,288	$17,711,526	$0	$17,711,526	$741,459	-$1,996,403	-11.27%	-$1,996,403	-$1,157,417
TOTAL LOWELL	$43,211,257	$120,947,585	$7,864,641	$172,023,483	$1,733,067	$173,756,550	$52,169,577	$8,958,320	5.16%	$8,958,322	$14,945,334
TOTAL CAPE+LOWELL	$90,860,363	$217,179,607	$13,948,016	$321,987,986	$2,778,993	$324,766,979	$106,002,705	$15,142,342	4.66%	$15,142,343	$26,211,745

RATE CLASS	PER ORDER REVENUE INCREASE AT 110% CA (L)	PER ORDER REVENUE TO BE REALLOCATI (M)	ROOM UNDER CAP (N)	PER ORDEF REVENUES FOR REALLOCAT (O)	PER ORDER REVENUE TO BE REALLOCAT (P)	PER ORDEI % INCREAS TOT REVEN AT EROR (Q)	PROPOSEI INCREASE GAF REVENUES (R)	PROPOSED INCREASE T(LDAF REVENUES (S)	PROPOSEI INCREASE GAF & LDA REVENUES (T)	PER ORDEF INCREASE GAF & LDAI REVENUES (U)	TARGET BASE REVENUE INCREASE (V)	TARGET BASE REVENUE REQUIREMEN (W)
COL GAS												
RESIDENTIAL												
NONHEAT (R-1 & R-2)	$293,293	$0	$351,684	$223,884	$165,493	5.01%	$11,516	$62,960	$74,476	74,476	$91,017	$1,997,152
HEAT (R-3 & R-4)	$9,263,187	$0	$278,484	$177,285	$9,161,988	8.78%	$559,406	$2,824,250	$3,383,656	3,383,656	$5,778,332	$40,359,250
COMMERCIAL (LLF)												
G/T-41	$1,325,140	$0	$661,102	$420,862	$1,084,900	7.27%	$83,750	$392,238	$475,988	475,988	$608,912	$5,487,789
G/T-42	$508,296	$0	$61,245	$38,989	$486,040	8.49%	$36,424	$176,938	$213,362	213,362	$272,678	$1,563,196
G/T-43	$108,421	$0	$31,302	$19,927	$97,046	7.95%	$7,632	$37,729	$45,361	45,361	$51,685	$328,135
COMMERCIAL (HLF)												
G/T-51	$692,654	$0	$417,788	$265,966	$540,832	6.93%	$48,440	$259,539	$307,979	307,979	$232,853	$2,316,568
G/T-52	$480,240	$0	$191,599	$121,973	$410,614	7.59%	$35,801	$184,521	$220,322	220,322	$190,292	$1,362,523
G/T-53	$734,180	$0	$145,282	$92,487	$681,385	8.24%	$57,485	$303,147	$360,632	360,632	$320,753	$1,777,232
GAS STREET LIGHTS (L)												
G-17	$1,345	-$1,859	$0	$0	$1,345	8.88%	$93	$521	$614	614	$731	$4,514
TOTAL CAPE	$13,406,756	-$1,859	$2,138,485	$1,361,373	$12,629,643	8.36%	$840,547	$4,241,843	$5,082,390	$5,082,390	$7,547,253	$55,196,359
												55,196,359
LOWELL	2.17											0
CAPE DIVISION												
RESIDENTIAL												
NONHEAT (R-1 & R-2)	$118,825	$342,335	$0	$0	$118,825	8.88%	$7,408	$26,610	$34,018	34,018	$84,807	$735,042
HEAT (R-3 & R-4)	$8,997,958	$3,727,018	$0	$0	$8,997,958	8.88%	$564,685	$2,649,037	$3,213,722	3,213,722	$5,784,236	$34,571,673
COMMERCIAL (LLF)												
G/T-41	$1,815,375	$396,984	$0	$0	$1,815,375	8.88%	$102,960	$557,739	$660,699	660,699	$1,154,676	$5,874,643
G/T-42	$1,172,372	$0	$993,279	$632,328	$811,420	6.14%	$74,748	$382,958	$457,706	457,706	$353,714	$2,855,804
G/T-43	$581,372	$0	$782,194	$497,950	$297,128	4.54%	$43,755	$199,342	$243,097	243,097	$54,031	$1,152,890
G/T-44												
COMMERCIAL (HLF)												
G/T-51	$586,169	$127,384	$0	$0	$586,169	8.88%	$61,055	$204,673	$265,728	265,728	$320,441	$1,800,325
G/T-52	$581,658	$0	$569,224	$362,371	$374,805	5.72%	$61,990	$211,068	$273,058	273,058	$101,747	$1,336,670
G/T-53	$1,572,435	$0	$2,729,853	$1,737,841	$580,423	3.28%	$212,275	$626,711	$838,986	838,986	-$258,563	$2,479,299
TOTAL LOWELL	$15,426,164	$4,593,722	$5,074,550	$3,230,489	$13,582,104	7.82%	$1,128,876	$4,858,138	$5,987,014	5,987,014	$7,595,090	$50,806,347
TOTAL CAPE+LOWELL	$28,832,920	$4,591,862	$7,213,035	$4,591,862	$26,211,747	8.07%	$1,969,423	$9,099,981	$11,069,404	11,069,404	15,142,343	106,002,706

Note: Schedule 11 is for illustrative purposes only.

XV. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.P.U. No. 1.1, M.D.P.U. No. 2.5, M.D.P.U. No. 4.1, and M.D.P.U. Nos. 101.7 through 114.1, filed by Boston Gas Company on April 16, 2010, to become effective on November 1, 2010, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. No. 1.1, M.D.P.U. No. 2.5, M.D.P.U. No. 4.1, and M.D.P.U. Nos. 301.1 through 314, filed by Colonial Gas Company on April 16, 2010, to become effective on November 1, 2010, are DISALLOWED; and it is

FURTHER ORDERED: That Boston Gas Company shall file new schedules of rates and charges designed to increase annual rate revenues by $41,451,838; and it is

FURTHER ORDERED: That Colonial Gas Company shall file new schedules of rates and charges designed to increase annual rate revenues by $16,475,029; and it is

FURTHER ORDERED: That Boston Gas Company and Colonial Gas 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 Boston Gas Company and Colonial Gas 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 gas consumed on or after November 2, 2010, but unless otherwise ordered by the Department, shall not become effective earlier than the seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/
Ann G. Berwick, Chair

/s/
Tim Woolf, Commissioner

/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.