UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act 1934

Date of Report (Date of earliest event reported): August 1, 2011

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**1-8858**	**02-0381573**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure

On August 1, 2011, the Massachusetts Department of Public Utilities ("MDPU") issued an Order (the "Order") approving increases of $3.3 million and $3.7 million in annual distribution revenues for the electric and gas divisions, respectively, of Fitchburg Gas and Electric Light Company ("Fitchburg" or the "Company"), Unitil Corporation's Massachusetts electric and natural gas utility subsidiary. The MDPU also approved revenue decoupling mechanisms and a return on equity of 9.2% for both the electric and gas divisions of the Company. The rate increase for Fitchburg's electric division included the recovery of $11.4 million of previously deferred emergency storm restoration costs associated with the December 2008 ice storm, which costs are to be amortized and recovered over seven (7) years without carrying costs.

Based on the MDPU Order, the Company expects to recognize a non-recurring pre-tax charge of $2.0 million in the third quarter of 2011, related to the December 2008 Ice Storm. The impact on 2011 earnings of this one time charge is $0.11 per share. The Order provides resolution to the open regulatory matters concerning the ratemaking treatment and cost recovery related to the December 2008 Ice Storm event.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

Number	Exhibit
99.1	MDPU Order dated August 1, 2011

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

UNITIL CORPORATION

By: /s/ Mark H. Collin

Mark H. Collin
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 5, 2011

EXHIBIT INDEX

Number	Exhibit
99.1	MDPU Order dated August 1, 2011

Exhibit 99.1

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

August 1, 2011

D.P.U. 11-01

Petition of Fitchburg Gas and Electric Light Company, d/b/a Unitil, pursuant to G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et seq., for Approval of a General Increase in Electric Distribution Rates, a Capital Cost Adjustment Mechanism, and a Revenue Decoupling Mechanism.

D.P.U. 11-02

Petition of Fitchburg Gas and Electric Light Company, d/b/a Unitil, 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.

APPEARANCE: Robert N. Werlin, Esq.
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-and-

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FOR: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY, d/b/a UNITIL
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Limited Participant

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I. INTRODUCTION

On January 14, 2011, Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Fitchburg" or "Company"), pursuant to G.L. c. 164, § 94, filed separate petitions with the Department of Public Utilities ("Department") to: (1) increase annual electric distribution revenues by $7,149,627;[1] and (2) increase annual gas distribution revenues by $4,447,529. Fitchburg was last granted a base rate increase for its electric division in 2008. Fitchburg Gas and Electric Light Company, D.P.U. 07-71 (2008). The Company was last granted a base rate increase for its gas division in 2007. Fitchburg Gas and Electric Light Company, D.T.E. 06-109 (2007).

In addition to the requested base rate increases, Fitchburg also seeks to implement: (1) separate revenue decoupling mechanisms for its electric and gas divisions; (2) a capital cost adjustment mechanism ("CCAM") that would allow the Company to adjust electric rates annually to recover the revenue requirement associated with future capital expenditures related to upgrades to its electric distribution system, customer additions, and electric reliability targeted infrastructure improvements; and (3) a targeted infrastructure recovery factor ("TIRF") that would allow the Company to adjust gas rates on an annual basis to recover the

1 The initial requested increase consists of two components: (1) $4,943,759 as a claimed electric base distribution revenue deficiency; and (2) $2,205,868 in annual recovery over a seven-year period of $13,026,642 in expenses associated with the Company's efforts to restore electric service to its customers following an ice storm in December 2008. Fitchburg's proposed recovery of storm-related expenses includes carrying charges at the Company's weighted average cost of capital, which initially was calculated at 8.58 percent and subsequently recalculated (see n.224 below).

revenue requirement associated with the replacement of non-cathodically protected steel mains and services and small diameter (i.e., eight inches or less) cast, wrought, or ductile iron distribution mains and other eligible facilities.

The Department docketed the Company's electric division petition as D. P. U. 11-01 and its gas division petition as D. P. U. 11-02. The Department has suspended the effective date of the proposed rate increases until August 2, 2011, to investigate the propriety of the Company's requests.

II. FITCHBURG/UNITIL CORPORATE STRUCTURE

Fitchburg is a wholly-owned subsidiary of Unitil Corporation ("Unitil"), a public company engaged in the retail distribution of electricity and natural gas in the states of Maine, Massachusetts, and New Hampshire (Exhs. Unitil-MHC-1, at 10 (electric); Unitil MHC-1, at 7 (gas)). Fitchburg provides electric and gas distribution service in Massachusetts to customers in the communities of Fitchburg, Townsend, Lunenburg and Ashby (Exhs. Unitil-MHC-1, at 10 (electric); Unitil-MHC-1, at 8 (gas)). In addition, Fitchburg provides natural gas service, but not electric service, in the towns of Gardner and Westminster (Exhs. Unitil-MHC-1, at 10-11 (electric); Unitil-MHC-1, at 8 (gas)). The Company serves approximately 27,900 electric customers and 15,200 gas customers in these Massachusetts communities (Exhs. Unitil-MHC- 1, at 11 (electric); Unitil-MHC- 1, at 8 (gas)).

Unitil operates two additional distribution utilities: Unitil Energy, which provides electric service in the southeastern seacoast and state capital regions of New Hampshire, and Northern Utilities, Inc., which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine (Exhs. Unitil-MHC-1, at 10 (electric); Unitil-MHC-1, at 7-8 (gas)).

Unitil is the parent company of Granite State Gas Transmission, which is an interstate natural gas pipeline company (Exhs. Unitil-MHC-1, at 10 (electric); Unitil-MHC-1, at 8 (gas)). In addition, Unitil owns the following subsidiaries: Unitil Power Corp.; Unitil Resources, Inc.; Unitil Realty Corp.; and Unitil Service Corp. ("USC"), which provides a wide variety of shared business functions to Unitil's utility affiliates on an "at-cost" basis (Exhs. Unitil-MHC- 1, at 11 (electric); Unitil-MHC- 1, at 9 (gas)).

III. PROCEDURAL HISTORY

On January 19, 2011, the Attorney General of the Commonwealth of Massachusetts ("Attorney General"), pursuant to G.L. c. 12, § 11E, filed a notice of intervention in both dockets. On February 16, 2011, the Department granted intervenor status in both proceedings to the Massachusetts Department of Energy Resources ("DOER"). On February 18, 2011, the Department granted intervenor status in these proceedings to the City of Fitchburg ("City"), and the Low-Income Weatherization and Fuel Assistance Program, the Massachusetts Energy Directors Association, and the Montachusett Opportunity Council (collectively, "Low Income Network"). On February 24, 2011, in D. P. U. 11-01, the Department granted intervenor status to the Town of Lunenburg and limited participant status to NSTAR Electric Company ("NSTAR Electric"). On the same day, the Department granted limited participant status in both proceedings to The Berkshire Gas Company ("Berkshire") and Environment Northeast ("ENE"), and limited participant status in D.P.U. 11-02 to NSTAR Gas Company ("NSTAR Gas").

On January 20, 2011, pursuant to G.L. c. 12, § 11E(b), the Attorney General filed a On January 20, 2011, pursuant to G.L. c. 12, § 11E(b), the Attorney General filed a Notice of Retention of Experts and Consultants in both dockets. On February 24, 2011, the Department approved the Attorney General's retention of experts and consultants.[2] Fitchburg Gas and Electric Light Company, D. P. U. 11-01, Order on Attorney General's Notice of Retention of Experts and Consultants (February 24, 2011); Fitchburg Gas and Electric Light Company, D.P.U. 11-02, Order on Attorney General's Notice of Retention of Experts and Consultants (February 24, 2011).

Pursuant to notice duly issued, the Department held two public hearings in the Company's service area on February 23, 2011. The Department held 20 days of evidentiary hearings between March 28, 2011 and April 29, 2011. The Department received written comments from several public officials and a number of Fitchburg ratepayers.

In support of the Company's filings, the following 14 witnesses provided testimony: (1) Mark Collin, the chief financial officer and treasurer of Unitil Corporation, the treasurer of Fitchburg, and the president of USC; (2) Thomas P. Meissner, the chief operating officer of Unitil Corporation, senior vice president of USC, and senior vice president of Fitchburg, Granite State Gas Transmission, Inc., Northern Utilities, Inc., and Unitil Energy Systems;

2 In D.P.U. 11-01, at 6, the Department approved the retention of experts and consultants not to exceed a cost of $250,000. In D.P.U. 11-02, at 5, the Department approved the retention of experts and consultants not to exceed a cost of $150,000.

(3) George E. Long, vice president of administration for USC; (4) Dr. Samuel Hadaway, principal, FINANCO, Inc.; (5) James D. Simpson, senior vice president, Concentric Energy Advisors, Inc.; (6) Paul M. Normand, principal, Management Applications Consulting, Inc.; (7) Edward Cunningham, director of consulting services, Environmental Consultants, Inc.; (8) Paul Appelt, president, Environmental Consultants, Inc.; (9) Michael Joyner, principal, Joyner Associates; (10) Elizabeth M. Shaw,[3] manager of benefits and payroll for Fitchburg; (11) Kevin E. Sprague, director of engineering, USC; (12) Richard L. Francazio, director, emergency management and compliance for Unitil Corporation; (13) Douglas Debski, senior regulatory analyst, USC; and (14) Richard A. Letourneau, Jr., director of electric operations, Unitil Corporation.

The Attorney General sponsored the testimony of the following ten witnesses: (1) James Connolly, consultant; (2) David E. Dismukes, consulting economist, Acadian Consulting Group; (3) David J. Effron, consultant; (4) 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; (5) Lee Smith, managing consultant and senior economist, La Capra Associates, Inc.; (6) Richard S. Hahn, principal consultant, La Capra Associates, Inc.; (7) Donna Ramas, senior regulatory analyst, Larkin & Associates, PLLC; (8) Daniel E. O'Neill, president and managing

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[3] The Company submitted pre-filed testimony from George Long, who was unable to appear at the evidentiary hearings. The Department and parties assented to the Company's proffer of Ms. Shaw to adopt Mr. Long's pre-filed testimony and appear for cross-examination on his behalf (see Tr. 4, at 316-317, 320-321).

consultant, O'Neill Management Consulting, LLC; (9) Charles A. Fijnvandraat, subcontractor to O'Neill Management Consulting, LLC; and (10) Helmuth W. Schultz, III., senior regulatory analyst, Larkin & Associates.

The City sponsored the testimony of the following eight witnesses: (1) Lisa A. Wong, Mayor of Fitchburg; (2) Marc Dohan, executive director, Twin Cities Community Development Corporation; (3) Brian Belliveau, Deputy Chief, City of Fitchburg Fire Department; (4) Charles A. Caron, commercial/residential real estate agent, Prudential Prime Properties; (5) Annie DeMartino, resident, City of Fitchburg; (6) Kenneth P. Jones, veterans service officer, City of Fitchburg; (7) Joana dos Santos, executive director, Cleghorn Neighborhood Center; and (8) Thomas Szocik, executive director, Fitchburg Redevelopment Authority.

On May 20, 2011, the Attorney General, DOER, and ENE submitted initial briefs in both dockets, and the Low Income Network submitted an initial brief in D.P.U. 11-02. On June 3, 2011, the Company submitted its initial brief in both dockets. On June 10, 2011, the Attorney General filed a reply brief in both dockets, and the Low Income Network filed a reply brief in D.P.U. 11-02. On June 17, 2011, the Company filed a reply brief in both dockets.

The evidentiary record consists of approximately 3,500 exhibits and responses to 141 record requests.[4] In addition, at the procedural conference on March 2, 2011, the Department on its own motion, pursuant to 220 C.M.R. § 1.10(3), incorporated into the record of these proceedings the entire record from Fitchburg Gas and Electric Light Company, D.P.U. 09-01-A (2009).[5]

IV. ATTORNEY GENERAL'S MOTION TO REOPEN RECORD

A. Introduction

On May 20, 2011, the Attorney General filed a motion, pursuant to 220 C.M.R. § 1.11(8), to reopen the record in these proceedings "to fully evaluate. . . *the net negative probative value* that can be deduced from . . . Exhibit Unitil-9" (emphasis in original) ("Motion"). On May 27, 2011, the Company submitted a response to the Attorney General's motion ("Response").[6]

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[4] Following evidentiary hearings, Record Request AG-58 was withdrawn by the Attorney General.

[5] On January 14, 2011, along with the initial filings in these cases, the Company filed a motion to consolidate ("Motion") the two dockets. In the interest of administrative efficiency, we have investigated both dockets simultaneously, held joint public hearings and joint evidentiary hearings, and will issue only one Order in both dockets. In light of these considerations, it is unnecessary to consolidate the dockets and, accordingly, the Motion is denied.

[6] On June 2, 2011, the Attorney General, without leave of the Department, submitted a reply to the Company's Response. The Department's procedural rules at 220 C.M.R. § 1.00 et seq. provide for the submission of a reply by a moving party only upon leave of the Department. Accordingly, the Department will not consider the Attorney General's reply in making its determination on the Attorney General's Motion.

Exhibit Unitil-9 is a typewritten letter dated April 21, 2011. It is addressed to a Company representative and bears the signature of the City's fire chief. The letter commends the work of another Company employee in helping to improve communication between various entities during storm related events. The letter was introduced for identification purposes on the last day of evidentiary hearings by the Company during the cross examination of the City's mayor (Tr. 20, at 2705). It was admitted into evidence with no objection from the Attorney General or any other party (Tr. 20, at 2712).

B. Positions of the Parties

1. Attorney General

The Attorney General submits that evidence discovered after the evidentiary hearings adjourned reveals that the Company employee who is the subject of Exhibit Unitil-9 actually initiated the correspondence by sending to the fire chief a draft letter and requesting that the fire chief sign it (Motion at 3, 4). The Attorney General contends that the Company employee requested the letter from the fire chief in order to receive an award of some type from the Company (Motion at 3). In support of the Motion, the Attorney General submits a similar draft letter of commendation purportedly submitted by the same Company employee in March 2010 to the City's commissioner of Department of Public Works ("DPW"), along with e-mail correspondence from the Company employee to the commissioner requesting that he sign the letter (Motion at Att. A).

The Attorney General argues that such newly discovered evidence reveals that the Company's employee has a record of being the initiator and author of recommendation letters, and that the City's public officials were misled about the purposes of these letters (Motion at 3, citing Att. A). The Attorney General asserts that the Department "should take this into account in evaluating the weight to be afforded [Exhibit] Unitil-9" and whether any further action is necessary (Motion at 3). Further, the Attorney General argues that the Company employee's acts of "self-promotion" mask the frosty relationship that actually exists between the Company and the City (Motion at 4). The Attorney General contends that the Company's exploitation of the fire chief and other City officials through the use of commendation letters "displays unrelentingly inappropriate behavior and a cultural climate at Unitil that has not changed an iota since the [Company's last] rate case" (Motion at 4). According to the Attorney General, the Company's failure to disclose the series of events underpinning the creation of Exhibit Unitil-9 "demonstrates that further actions by the Department are required to hold the Company to an appropriate level of conduct" (Motion at 4).

Based on the above, the Attorney General submits that good cause exists to reopen the record in these proceedings and admit the March 2010 draft letter of commendation and related email correspondence between the Company's employee and the DPW commissioner (Motion at 1, 4). According to the Attorney General, this newly discovered evidence raises questions concerning Fitchburg's credibility as to its relationship with the City and may expose the "less than meritorious" motives for the Company to sponsor Exhibit Unitil-9 (Motion at 1, 4). The Attorney General asserts that the new evidence submitted in support of the Motion should be admitted into the evidentiary record of these proceedings or Exhibit Unitil-9 should be given negative probative value (Motion at 4).

2. Fitchburg

The Company objects to the Attorney General's motion to reopen the record in this matter. The Company argues that public officials are routinely requested to provide letters of recommendation and it is understood by the officials that such letters memorialize positive achievements and good work and will be relied upon by the recipient as proof of positive character when reputation is at issue (Response at 3). As such, Fitchburg contends that the Attorney General's assertion that the Company obtained the letters using surreptitious means to bolster its position in the rate proceedings is without merit (Response at 3). Further, the Company notes that it only introduced Exhibit Unitil-9 in rebuttal to the City's mayor's testimony that communications between the Company and the City had not improved (Response at 3).

Fitchburg argues that Exhibit Unitil-9, as well as other letters of commendation, were solicited by the Company's employee "in order to obtain support and recognition of a number of achievements" (Response at 1-2). In support of its position, the Company submits additional correspondence between its employee and the City's fire chief regarding Exhibit Unitil-9 (Response at Att. A). Fitchburg notes that the City's fire chief requested that the Company's employee provide a sample commendation letter (Response at 2, citing Att. A). Further, the Company contends that its employee requested that the fire chief "edit at will" the contents of the sample letter (Response at 2, citing Att. A). In addition, the Company asserts that there is no evidence that the City's fire chief ever disavowed any of the opinions in the sample or final letter (Response at 2).

In addition, with respect to the March 2010 correspondence between the same employee and the City's DPW commissioner, the Company claims that the Attorney General failed to provide the commissioner's actual letter of commendation, in which the commissioner expanded upon the sample letter to provide additional favorable feedback to the Company (Response at 2, citing Att. B). The Company contends that there is no evidence that the DPW commissioner retracted his opinions and states that the commendation letter was requested only after the collaboration on several matters between the Company's employee and the DPW commissioner (Response at 2).

For the reasons discussed above, the Company asserts that it is unnecessary to reopen the record to admit the additional evidence sought by the Attorney General (Response at 3). If the Department is inclined to reopen the record, the Company requests: (1) that the entire email exchanges between the Company's employee and the City's fire chief and DPW commissioner be admitted into the record; and (2) that additional hearings be held so that the Company can call additional witnesses on this matter (Response at 3).

C. Standard of Review

The Department's procedural rule on reopening hearings, 220 C.M.R. § 1.11(8), states, in pertinent part, "[n]o person may present additional evidence after having rested nor may any hearing be reopened after having been closed, except upon motion and showing of good cause." Good cause for purposes of reopening the record has been defined as a showing that the proponent has previously unknown or undisclosed information regarding a material issue that would be likely to have a significant impact on the decision.

Machise v. New England Telephone and Telegraph Company, D.P.U. 87-AD-12-B at 4-7 (1990); Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989); Tennessee Gas Pipeline Company, D.P.U. 85-207-A at 11-12 (1986).

D. Analysis and Findings

The Attorney General bears the burden of establishing that the Department, following the conclusion of evidentiary hearings on April 29, 2011, should reopen the record and accept previously unknown or undisclosed evidence surrounding the drafting of Exhibit Unitil-9 because such information concerns a material issue that would likely have a significant impact on our decision in these cases. The Attorney General argues that the circumstances surrounding the drafting of Exhibit Unitil-9 raise questions concerning the credibility of Fitchburg's witnesses as to reasons for the commendation letter, how it would be used by the Company's employee, and the nature of the Company's relationship with the City (Motion at 3-4).

Absent any convincing showing of fraud or forgery in procuring the commendation letter, we decline to reopen the record for the purposes of admitting additional evidence concerning the factual background surrounding the drafting of Exhibit Unitil-9. We find that the Attorney General has failed to demonstrate that the circumstances surrounding the drafting of Exhibit Unitil-9 are likely to have a significant impact on our decision in these cases. The Department will give Exhibit Unitil-9 appropriate evidentiary weight, taking into consideration the manner in which it was introduced into evidence and in light of all of the evidence in the record concerning the communications and overall relationship between the Company and the City.[7] Accordingly, the Attorney General's Motion is denied.

V. RECOVERY OF WINTER STORM 2008 REPAIR AND RESTORATION COSTS

A. Introduction

1. Overview

The Company seeks to recover the costs related to a storm that occurred during December 2008 ("Winter Storm 2008" or "Storm"). The Storm was a significant event, depositing as much as one and one-half inches of ice in parts of the Company's service territory. As a result, much of the damage wreaked would have occurred regardless of the Company's level of preparedness or the quality of its response. As we discuss in detail below, however, the Company's preparation was in fact inadequate and its response overwhelmingly deficient. The Department's approach here is to allow Storm-related costs that, as far as we have been able to determine, are attributable to the magnitude of the Storm itself. We disallow those costs, however, that are associated with the Company's mismanagement.

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[7] The issue of the extent of communication between the Company and the City was examined in the context of the December 2008 ice storm during the Department's investigation into Fitchburg's storm response efforts. See D.P.U. 09-01-A at 126-128. The record from that proceeding is incorporated into the record in these cases. Further, the Attorney General had ample opportunity in these proceedings to explore the Company's and City's communicative relationship and to present relevant evidence to support her position.

The costs that the Company seeks to recover related to the Storm and to future storm management fall into the following categories: (1) legal and consultant costs that the Company incurred during Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 09-01-A (2009), the Department's investigation into the Company's preparation for and performance during the Storm, addressed in Section V.B, below; (2) costs incurred to repair damage and restore service following the Storm, addressed in Section V.C, below; (3) retroactively awarded overtime pay for salaried employees who worked during the Storm and the restoration period, addressed in Section V.C, below; (4) carrying charges on costs to restore service, addressed in Section V.C, below; (5) costs associated with two Storm-related witnesses in this proceeding, addressed in Section X.C, below; (6) costs to implement a proposed vegetation management program based on the recommendation of a Department-directed third party consultant report, addressed in Section X.O, below; and (7) costs to address future storms (a storm fund), addressed in Section X.P, below. In addition, the Company seeks recovery of an amount to cover incentive pay for management, addressed in Section X.A, below.

The total cost of the Company's Storm-related request is $22,120,286. In this Order, the Department allows recovery of $15,165,794 of this amount, thereby disallowing $6,954,492, or approximately one-third of the Company's request. As discussed in Section XI, below, the Department also adjusts the Company's return on equity ("ROE") in part to reflect its poor Storm restoration performance. The impact on the Company of this Storm-related adjustment is in addition to the disallowance of one-third of the Company's Storm-related request.

2. Description of Storm

Between December 11-12, 2008, the northeastern United States experienced Winter Storm 2008, a significant storm event that caused electric service outages to over a million customers in the New England states, New York, and Pennsylvania. D.P.U. 09-01-A at 19-20. During that time, up to one and one-half inches of freezing rain fell in the Company's service territory. D.P.U. 09-01-A at 19. Winter Storm 2008 disrupted electric service to 100 percent of the Company's 28,500 electric customers. D.P.U. 09-01-A at 20,91. Many of those customers were without power for well over a week and some for up to two weeks. D.P.U. 09-01-A at 91. On December 25, 2008, the final customers without power had their electric service restored. D.P.U. 09-01-A at 90-91.

3. Investigation into the Company's Preparation and Performance During Winter Storm 2008, D.P.U. 09-01-A

On January 7, 2009, the Department issued an order opening an investigation into the efforts by the state's four electric distribution companies to prepare for and restore power following Winter Storm 2008. D.P.U. 09-01-A at 1. The Department's investigation into the Company's preparation and performance in Winter Storm 2008 was docketed as D.P.U. 09-01-A.

On November 2, 2009, following an extensive investigation, the Department issued its Order in D.P.U. 09-01-A. The Order catalogued numerous failures by the Company in its planning and preparation for a major storm. Specifically, the Department found that the Company’s lack of planning and training for a significant storm event left it unprepared to respond to the magnitude of system damage that it experienced during Winter Storm 2008. D.P.U. 09-01-A at 47. The Department determined that the Company’s lack of planning led to: (1) its inability to restore service to its customers in a timely manner; (2) its failure to communicate accurate and useful information to the public; and (3) its failure to coordinate its restoration efforts with local public safety officials. D.P.U. 09-01-A at 47. Further, the Department identified failures in: (1) the Company’s pre-storm preparation; (2) external resource acquisition; (3) damage assessment; (4) communication efforts with the public, municipal officials, local safety officials, and life support customers; and (5) adherence to its tree trimming schedule. D.P.U. 09-01-A at 60, 71-72, 83-84, 121, 125, 127-128, 135, 158-159. The Department concluded that the Company’s numerous deficiencies in preparing for and responding to Winter Storm 2008 resulted in a failure to meet its public service obligation to provide safe and reliable service. D.P.U. 09-01-A at 52, 59, 72, 84, 121, 125.

The Company did not seek recovery of the costs incurred to restore power following the Storm in D.P.U. 09-01-A, nor did the Department conduct a detailed evaluation of those expenses. D.P.U. 09-01-A at 195-196. Rather, the Department stated that it would perform a prudence review of the storm costs in the Company’s next rate case to determine whether recovery was appropriate, and that it would disallow any imprudently-incurred storm costs.

D.P.U. 09-01-A at 196.[8] Additionally, the Department stated that we would take the Company's poor storm restoration performance into consideration during the Company's next rate case when establishing the Company's ROE. D.P.U. 09-01-A at 199. In this section, we begin by addressing the recovery of legal and regulatory costs incurred by the Company in D.P.U. 09-01-A. We then turn to examining the prudence of the costs incurred to restore power following Winter Storm 2008.

B. D.P.U. 09-01-A Investigation Costs

1. Introduction

The Company incurred $1,296,629 in legal and consulting costs to respond to the Department's investigation in D.P.U. 09-01-A (Exh. Unitil-MHC-1, at 32 (electric)). The Company expensed $112,067 of these costs in 2008 and, accordingly, does not seek recovery of that amount (Exh. Unitil-MHC-1, at 32 (electric)). The Company proposes to recover the remaining $1,184,562 incurred in 2009 by amortizing the expenses over a three-year period (Exhs. Unitil-MHC- 1, at 32 (electric); DPU 1-14 (electric)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that 30 percent of the legal and regulatory costs associated with D.P.U. 09-01-A should be disallowed because the Company's imprudence was a

[8] In 2009, the Company sought and received approval from the Department to defer $11,515,848 in Storm-related expenses for review in the Company's next rate case. Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 09-61, at 14 (2009).

contributing factor to incurring the costs (Attorney General Brief at 139). Further, the Attorney General asserts that the remaining legal and regulatory costs associated with D.P.U. 09-01-A should be amortized over the same period allowed for Winter Storm 2008 restoration costs (Attorney General Brief at 139). She suggests that the costs be amortized over ten years without rate base recognition and/or any carrying costs (Attorney General Brief at 139). Accordingly, she recommends that the Company be allowed to recover $829,193 over ten years, or $82,919 per year (Attorney General Brief at 139, citing Exhs. AG-HWS-1, at 30 (electric); AG-HWS-6 (electric)).

b. Fitchburg

According to the Company, its request to amortize $1,184,562 in legal and regulatory costs associated with D.P.U. 09-01-A is consistent with the Department's precedent for recovery of extraordinary costs incurred during a test year (Company Brief at 52, citing Boston Edison Company, D.P.U. 85-266-A/271-A at 95-99 (1986)). The Company asserts that amortizing[9] these expenses over a three-year period reduces test year expenses by $789,708 (Company Brief at 52, citing Exh. Unitil-MHC-1, at 31-32 (electric)). The Company argues that the amortized expense is a representative level for inclusion in cost of service (Company Brief at 52).

[9] In its brief, the Company contends that it proposes to normalize the legal and regulatory costs over a three-year period (Company Brief at 52). The record, however, indicates that it seeks to amortize these expenses over a three-year period (Exh. DPU-1-14 (electric)).

3. Analysis and Findings

The Company has a public service obligation to provide safe and reliable service to its customers. D.P.U. 09-01-A at 6-8, citing Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, at 368 n.4 (1986); Fitchburg Gas & Electric Light Company v. Department of Public Utilities, 394 Mass. 671 (1985). The Department's goal as the oversight agency of gas and electric distribution companies is to ensure that such companies provide safe and reliable service in the Commonwealth.[10]

The Company seeks recovery for the cost of lawyers and consultants it hired to represent the Company in the Department's proceeding investigating the Company's Storm preparation and response. Following an exhaustive review that included two public hearings in

[10] D.P.U. 09-01-A, at 8, citing 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 1 (2009) (the Department's comprehensive oversight powers are to ensure reliable and safe services to the public by gas and electric distribution companies); Revenue 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) (the Department's goal is 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 4 (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) (the Department must ensure that utilities subject to its jurisdiction provide safe and reliable service at the lowest possible cost to society); see also Rulemaking on Sales of Electricity by Small Power Producers and Cogenerators, D.P.U. 84-276-A at 16 (1986) (the Department has the responsibility for ensuring that a company fulfills its public service obligation).

the Company's service territory, 240 public commenters, 80 written comments, five days of evidentiary hearings, 442 exhibits, and a lengthy Order, the Department concluded in that proceeding that the Company failed to meet its public service obligation in multiple aspects of its Storm response, including planning and training for a significant storm, pre-storm preparation, damage assessment, acquisition of external crews, communication with the public through its call center and public service announcements, and communication with life support customers. D.P.U. 09-01-A at 3, 5, 52, 60 70, 71-72, 83-84, 121, 125, 135-136. The Department determined that each of these deficiencies constituted a failure to meet the Company's public service obligation to provide safe and reliable service. D.P.U. 09-01-A at 52, 60, 70, 71-72, 83-84, 121, 125, 135-136.[11]

The Department has traditionally evaluated recovery of legal expenses based on whether the expenses are an annually recurring expense, a periodically recurring expense, an extraordinary non-recurring expense qualified for amortization, or a non-extraordinary non-recurring expense not qualified for inclusion in cost of service. See, e.g., Dedham Water Company, D.P.U. 84-32, at 21-23 (1984); Nantucket Electric Company, D.P.U. 1530, at 30-31 (1983); Boston Gas Company, D.P.U. 1100, at 94-95 (1982); Commonwealth Electric Company, D.P.U. 956, at 27 (1982). The Department concludes, however, that applying traditional ratemaking principles to the recovery of legal and consultant costs

[11] Additionally, the Department found that the Company's communication with public officials was "severely deficient," but did not specifically conclude that this insufficiency constituted a failure to meet its service obligation. D.P.U. 09-01-A at 127-128.

associated with an investigation into a company's fundamental failure to provide safe and reliable service does not further the overarching goal of the Department: to ensure that companies fulfill their public service obligation. Rather, based on the broad oversight authority provided to the Department in G.L. c. 164, § 76 to regulate gas and electric distribution companies, and to reinforce to the Company as well as other distribution companies the importance of fulfilling their obligation to provide safe and reliable service, the Department will deny legal and consulting expenses associated with proceedings in those rare instances in which the Department determines that a company failed to meet its public service obligation.

We acknowledge that companies may typically seek to recover legal expenses incurred relative to their defense against legal actions brought against them, and that recovery of these costs is not contingent upon the final outcome of the proceedings. Oxford Water Company D.P.U. 88-171, at 28 (1989); Wylde Wood Water Works, D.P.U. 86-93, at 14 (1987); D.P.U. 1100, at 106-107; Massachusetts Electric Company, D.P.U. 19376 (1978); Fitchburg Gas and Electric Light Company, D.P.U. 19084, at 41-42 (1977); Cape Cod Gas Company, D.P.U. 19036 (1977). We have not been faced with a situation, however, in which a company has so thoroughly mismanaged its response to a situation like Winter Storm 2008 and compromised its responsibilities to the public.[12] The Department has previously stated that it

[12] The Company's performance has been the subject of universal condemnation, both on the part of customers and ultimately by the Department in D.P.U. 09-01-A. For example, over one-third of commenters at the public hearings argued that the Company should be "removed from providing service" based on its poor response and treatment of its customers. D.P.U. 09-01-A at 16-17. Additionally, customers presented the Department with a petition to disenfranchise the Company that was signed by over 4,000 customers. D.P.U. 09-01-A, February 3, 2009 Public Hearing, Exh. 1. Finally, the Commonwealth enacted new legislation to address, in part, the Company's Storm response. That legislation, G.L. c. 164, §§ 1J, 85B: (1) provides the Department with the authority to promulgate rules and regulations to establish standards of acceptable performance for emergency preparation and restoration of service; (2) provides penalty authority for violation of those standards; (3) requires distribution companies to annually submit to the Department an emergency response plan for review and approval; and (4) permits the Department to deny service restoration cost recovery if a company's failure to implement its emergency response plan results in extended service outages. See also 220 C.M.R. § 19.00 et seq.

"has no obligation to insulate shareholders who, through the actions of their own management, sustain self-inflicted wounds." Boston Edison Company, D.P.U./D.T.E. 97-95, at 49 (2001); see also Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84, at 50 n.38 (2000); Blackstone Gas Company, D.P.U. 511, at 7 (1981). In certain cases, for example, we have held shareholders, not ratepayers, responsible for civil fines, insurance premiums paid to protect the company against acts of bad faith, and the costs associated with independent management audits. Boston Gas Company, D.P.U. 88-67, at 143 (Phase I) (1988); Western Massachusetts Electric Company, 86-280-A at 97 (1987); New England Telephone and Telegraph Company, D.P.U. 86-33-G at 141-142 (1989); see also New England Gas Company, D.P.U. 08-110, at 1 (2010). Here, the Company demonstrated what can be fairly characterized as an egregious failure to meet its public service obligation in multiple aspects of its preparation and response to Winter Storm

2008.[13] To require ratepayers to be responsible for the Company's legal and consultant expenses associated with the Department's lengthy and extensive investigation into the Company's serious failures to provide safe and reliable service would be both unreasonable and unconscionable. The Department finds that the comprehensive nature of the Company's failure to provide safe, reliable service warrants denying recovery of all legal and consulting costs associated with those failures, and supports the conclusion that the Company's shareholders should absorb the costs of defending the Company in this unique set of circumstances. Accordingly, we deny recovery of $1,184,562 in costs associated with D.P.U. 09-01-A, which results in a reduction to the Company's cost of service of $394,854 over that proposed by the Company.

C. Winter Storm 2008 Repair and Restoration Costs

1. Fitchburg's Proposal

a. Introduction

We now address recovery of the costs associated with restoring power to customers following Winter Storm 2008. The Company seeks recovery of $15,061,777 in costs related to restoring power in Winter Storm 2008, as well as an additional $3,762,147 in carrying charges (Exhs. Unitil-MJ-3, at 4 (electric); Sch. RevReq-14, at 1 (Supp. 3) (electric);

13 The Department concluded, for example, that the Company's failures to plan, act, or ask for assistance on behalf of life support customers was "an intolerable failure of its duty to its most vulnerable customers . . . and represents a fundamental failure of the Company to meet its public service obligation as a franchised utility in the Commonwealth." D.P.U. 09-01-A at 135-136.

DPU-24-5 (Supp.) (electric)). According to the Company, of the $15,061,777 in Storm costs, $3,468,815 are capitalized expenses, while $11,592,962 are deferred[14] incremental storm restoration and repair expenses (Exhs. Unitil-MJ-3, at 4 (electric); Unitil-MHC-1, at 44 (electric); DPU-24-5 (Supp.) (electric)).[15] The Company proposes to recover the $11,592,962 of incremental costs over a seven-year period through a uniform storm recovery adjustment factor of $0.00498 per kilowatt hour ("kWh") (Exhs. Unitil-MHC-1, at 44 (electric); Unitil-MJ-3, at 4 (electric); Sch. RevReq-14, at 1 (Supp. 3) (electric); DPU-24-5 (Supp.) (electric)). The annual storm cost recovery adjustment factor is projected to recover $2,193,587 annually, including carrying charges at the Company's weighted average cost of capital ("WACC") on the unrecovered balance, net of the associated accumulated deferred income tax balance (Exhs. Unitil-MHC-1, at 44 (electric); Sch. RevReq-14, at 1 (Supp. 3) (electric)).

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14 On December 30, 2009, the Department approved deferral accounting treatment to $11,515,848 of Storm-related expenses for review in the Company's next rate case. D.P.U. 09-61, at 14. The Department made no findings as to whether the subject expenses were reasonable or whether they could be recovered from ratepayers. D.P.U. 09-61, at 14.

15 Initially, the Company requested a total of $15,125,745 in Storm costs, of which it stated that $11,656,930 were deferred Storm costs (Exhs. Unitil-MJ-3, at 4 (electric); Unitil-MHC-1, at 44 (electric)). Subsequently, the Company reduced its requested deferred Storm costs by $63,968 for amounts it billed to Verizon for tree-related work, but had not removed from the deferred Storm costs (Exh. DPU-24-5 (Supp.) (electric)). The Department attributes this reduction to the total reported contractor and related services cost category.

b. Cost Categories

i. Introduction

According to the Company, the $15,061,777 in Storm costs includes the following: (1) $14,013,658 in contractor and related services; (2) $530,495 in incremental payroll (including USC labor);[16] (3) $324,975 in materials and supplies; (4) $153,293 for transformers; and (5) $39,356 for transportation (Exhs. Unitil-MJ-3, at 4 (electric); DPU-24-5 (Supp.) (electric)). The Company capitalized $3,468,815 of the total expenses (Exh. Unitil-MJ-3, at 4 (electric)).

ii. Contractor and Related Services

The $14,013,668 in contractor and related services is associated with the Company hiring mutual aid crews and services to assist in the restoration effort (Exhs. Unitil-MJ-3, at 4 (electric); DPU-24-5 (Supp.) (electric)). According to the Company, contractors hired during storm emergency periods are usually paid at premium rates; typically, they are paid double-time for all time worked (Exh. Unitil-MJ-3, at 4 (electric)). In addition, the Company paid for contractor crew rest time as well as meal and lodging costs (Exh. Unitil-MJ-3, at 4 (electric)). Contractor emergency rates are governed by a contractor's applicable union bargaining agreement, if applicable, or by a contractor's standard service contract (Exh. DPU-1-3 (electric)). The charter for the Northeast Mutual Assistance Group ("NEMAG"), of which the Company is a member, governs payment of meals and lodging

[16] As part of its incremental payroll, the Company proposes to recover overtime pay salaried Company and salaried USC employees who worked during the restoration.

(Exh. DPU 1-11 (electric)).[17] Further, the Company must pay for mobilization and demobilization costs, which are the time and expenses required to bring crews to the job site and then return crews to their base locations (Exh. Unitil-MJ-3, at 4 (electric)).

According to the Company, it required outside contractor crews through January 24, 2009 to repair storm damage (Exh. Unitil-MJ-3, at 4 (electric)). Some contractors were released before the end of 2008, while the Company kept others crews through the first three weeks of January (Exh. Unitil-MJ-3, at 4 (electric)). The crews who remained in January were paid storm emergency wages, which the Company states is standard industry practice (Exh. Unitil-MJ-3, at 4 (electric)).

The Company states that it tracked each resource from commitment, arrival, and release (Exh. Unitil-MJ-3, at 5 (electric)). The Company claims that its validation process ensured that contractor invoices contained accurate information, and that the invoices were cross-referenced with timesheets, if provided, as well as dates specified on the invoice and listed equipment and personnel (Exh. Unitil-MJ-3, at 5 (electric)). The Company notes that while some contractors only provided dates of service and the operating center in which they worked, the Company matched these invoices to other sources of information, including crew assignment sheets, construction work orders, crew logs, and sign-in sheets (Exh. Unitil-MJ-3, at 5 (electric)).

[17] NEMAG is a group of New England and Canadian electric utilities whose members may assist one another to respond to emergencies. D.P.U. 09-01-A at 31-32 n.35. The NEMAG charter incorporates the Edison Electric Institute ("EEl") suggested governing principles as they relate to payment for meals and lodging (Exh. DPU-1-11, Atts. 1-3 (electric)).

iii. Incremental Payroll

The $530,495 in incremental payroll expenses are direct charges by Company hourly employees, as well as overtime pay charged to the Storm by Company and USC salaried employees (Exh. Unitil-MJ-3, at 5 (electric)). The Company's hourly employees emergency pay rates are based on collective bargaining agreements, and include payment for "rest time" following long stretches of work in the course of a day (Exh. Unitil-MJ-3, at 5 (electric)). The Company did not charge straight-time wages for either Company salaried employees or USC employees to the Storm (Exh. Unitil-MJ-3, at 5-6 (electric)). Following Winter Storm 2008, but made effective retroactively to December 1, 2008, the Company adopted a policy permitting overtime pay for salaried Company and USC during storm emergencies (Exh. DPU 22-6 (electric)).

iv. Materials and Supplies/Transformers/Transportation

The $324,975 in materials and supplies costs represent inventory used during the restoration (Exh. Unitil-MJ-3, at 6 (electric)). The Company compared the physical inventory of its materials and supplies that it conducted at the end of November 2008 with the inventory executed at the end of January 2009 to determine materials and supplies used during the Storm (Exh. Unitil-MJ-3, at 6 (electric)). The $153,293 in transformer expenditures were for purchases to repair and replace transformers damaged in the Storm (Exh. Unitil-MJ-3, at 6 (electric)). The $39,356 in transportation expenses represent the cost of Company-owned vehicles and equipment used during the restoration (Exh. Unitil-MJ-3, at 6 (electric)).

c. Fitchburg Consultant's Review of Storm Costs

To support its recovery of the Winter Storm 2008 costs, the Company hired a consultant to (1) validate the accuracy of the incurred costs; (2) determine whether any action taken by the Company increased the amount of the costs incurred; and (3) assess whether the total cost incurred was reasonable (Exh. Unitil-MJ-1, at 3 (electric)). According to the Company's consultant, the Storm costs were accurately compiled (Exh. Unitil-MJ-1, at 10 (electric)). The consultant reached this determination by reviewing the detailed transactional reports of charges, evaluating supporting documentation,[18] ensuring that the amounts paid agreed with supporting documentation and any applicable vendor contracts, and interviewing Company personnel responsible for approving the invoices or managing the storm response as appropriate (Exh. Unitil-MJ-1, at 9 (electric)).

The Company's consultant also evaluated whether additional costs were incurred as a result of delay in the emergency restoration process, inadequate damage-assessment resources, or the length of the schedule for vegetation management activities (Exh. Unitil-MJ-1, at 11-12 (electric)). According to the Company, the costs incurred to restore power following the Storm were a function of the Storm's severity and extensive damage to the Company's system caused by heavy ice and bending or fallen trees, rather than to any deficiencies on the part of

[18] Such documentation included time sheets, hotel invoices, restaurant invoices, and receipts (Exh. Unitil-MJ-1, at 8 (electric)).

the Company in restoring power (Exh. Unitil-MJ-1, at 10-11, 15-20 (electric)). The Company points out that the Storm costs are comprised almost exclusively of contractor costs, with a relatively small portion of the costs being materials and supplies (Exh. Unitil-MJ-1, at 14 (electric)). The Company states that the damage caused by Winter Storm 2008 resulted in a "fixed" number of repairs that needed to be addressed, that the costs are a direct function of the number of repairs needed to restore service, and that the passage of time did not increase the number of repairs or the costs of those repairs (Exh. Unitil-MJ-1, at 14 (electric)). The Company submits, for example, that the total number of crew days required to complete a task, as well as the costs associated with those crews, would be the same whether a single crew accomplished a task in ten days or five crews completed the task in two days (Exh. Unitil-MJ-1, at 14 (electric)).[19]

Additionally, according to the Company, a more comprehensive damage assessment did not affect the number of crew hours required to do the repair work, and delay in obtaining crews did not increase the costs because any such delay would not have lessened the extent of the damage or reduced the cost of repairs (Exh. Unitil-MJ-1, at 17-18 (electric)). Further, the Company asserts that traditional cyclical vegetation management is not designed to prevent damage to an electric distribution system in an ice storm of the magnitude of Winter Storm 2008 (Exh. Unitil-MJ-1, at 19 (electric)). Rather, the Company states that even if tree

[19] The time required to restore power in the Storm is measured by crew days, with a crew day consisting of 16 hours, or two normal work shifts. See D.P.U. 09-01-A at 85 n.79, citing Exh. FGE-7, at 36.

branches were in contact with overhead lines because of insufficient trimming, the impact would be minimal because of the devastating damage associated with falling, ice-laden trees (Exh. Unitil-MJ-1, at 20 (electric)). In short, the Company concludes that the repair costs were not affected by the nature, duration, or effectiveness of its restoration efforts (Exh. Unitil-MJ-1, at 10-11 (electric)).

Finally, the Company's consultant evaluated the overall reasonableness of the Storm costs by comparing the Company's restoration costs with those expenses incurred by Western Massachusetts Electric Company ("WMECo") and Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid")[20] during Winter Storm 2008 (Exh. Unitil-MJ-1, at 23 (electric)). According to the Company, its total crew cost per day was $7,809, approximately 14 percent less than National Grid's per day crew costs and within five percent of the WMECo's per crew day costs (Exh. Unitil-MJ-1, at 23 (electric)). Additionally, the Company contends that its cost per foot of wire replaced, rate of replacing feet of wire per crew day, and pole replacement rate all compare favorably to those of WMECo and National Grid (Exh. Unitil-MJ-1, at 24-25 (electric)).[21]

[20] The Department notes that National Grid is not a separate corporate entity. The reference to National Grid as opposed to the specific electric and gas distribution companies doing business as National Grid is simply for administrative ease.

[21] According to the Company, its cost of wire replaced was $78 per foot, over a third less than WMECo's and the same as National Grid's (Exh. Unitil-MJ-1, at 24 (electric)). Additionally, the Company replaced 138 feet of wire per crew day, compared to WMECo's rate of 95 feet per crew day and National Grid's rate of 153 feet per day (Exh. Unitil-MJ-1, at 24 (electric)). Finally, the Company replaced 244 poles at a rate of 5.7 crew days per pole compared with WMECo's and National Grid's rates of 8.1 and 9.9 crew days per pole, respectively (Exh. Unitil-MJ-1, at 25 (electric)).

2. Positions of the Parties

a. Attorney General

i. Documentation of Storm Costs

According to the Attorney General, although some contractor invoices lacked back-up time sheets, most costs associated with contractor and related services are supported by documentation (Attorney General Brief at 125). The Attorney General asserts, however, that that the Company's ability to support payment of these costs does not demonstrate that the costs were reasonable (Attorney General Brief at 125). The Attorney General argues that although the Company's consultant confirmed certain costs through conversations with Company and USC employees, there are no notes of those conversations or the cost verification process (Attorney General Brief at 125, citing Tr. 9, at 1015-1016). Additionally, the Attorney General contends that the Company's consultant produced no documentation of internal labor costs and capitalized costs, but instead indicated that verification of these costs was based on undocumented discussions (Attorney General Brief at 125-126, citing Tr. 9, at 1017-1019). Further, the Attorney General argues that National Grid, the largest supplier of labor and equipment, did not provide sufficient information to ascertain contractor crew rates (Attorney General Brief at 123-124, citing Exh. AG-HWS-5, at 2; Tr. 9, at 1151). Finally, the Attorney General contends that the Company should reduce its Storm costs by $271,003 to recognize Verizon's share of tree-related costs incurred during the Storm (Attorney General Brief at 129).

The Attorney General contends that the Company's consultant's review of costs fails to demonstrate that the costs are reasonable or prudent (Attorney General Brief at 128-129). Rather, the Attorney General argues that the Company's consultant did not perform a thorough cost review (Attorney General Brief at 127). The Attorney General asserts that the Company's consultant did not verify contractor rates listed on invoices by comparing them with those specified in bargaining unit agreements, did not perform an independent verification of contractor rates, and stated that his team would not have inquired whether the contractor rates were accurate or reasonable because that was not the job the consultant was asked to do (Attorney General Brief at 127, citing Tr. 9, at 1078-1080). Further, the Attorney General takes issue with the Company's consultant opining that a $977,987.56 invoice from Exelon/Philadelphia Electric Company ("PECo") invoice was reasonable, even though the PECo invoice was not supported by time sheets[22] and the consultant may not have even seen the bill (Attorney General Brief at 126, citing Tr. 9, at 1058-1060). Additionally, the Attorney General contends that the Company's consultant was unaware of whether the Company recorded the arrival date and time of those repair crews, and contends the record demonstrates that the Company tracked crews on erasable "white boards" (Attorney General Brief at 126-127, citing Tr. 9, at 1145-1146). The Attorney General points out that the Company's

[22] The Company subsequently obtained and submitted PECo time sheets (Exh. DPU-24-15 (rev.) Att. 2 (electric)).

consultant did not discuss with the Company whether it considered obtaining local crews at standard rates rather than paying double time when the Company was working on permanent repairs to the distribution system after power was restored (Attorney General Brief at 127-128). Further, the Attorney General asserts that the Company's consultant does not have experience in performing this type of storm cost verification (Attorney General Brief at 127-128).

ii. Effect of Performance on Storm Costs

(A) Introduction

The Attorney General argues that the Department should significantly reduce the amount of Winter Storm 2008 costs subject to recovery from ratepayers because the Company failed to (1) implement a regular tree trimming cycle consistent with industry standards or the cycles it had adopted, and (2) properly plan and train for responding to storms (Attorney General Brief at 105). The Attorney General contends that these failures significantly increased Storm costs (Attorney General Brief at 106). The Attorney General recommends that, based on the record in D.P.U. 09-01-A and in this proceeding, the Department should reduce the Company's proposed Storm cost recovery by at least $5,916,121, and that the remaining $5,740,809 should be deferred without a return until the transition charge terminates in 2014 and, thereafter, amortized over seven years without a return (Attorney General Brief at 106, 150).

(B) Historic Vegetation Management Practices

The Attorney General asserts that the “major factor contributing to the cost of restoring the service and to the time it took to restore service was the Company’s failure to address vegetation maintenance,” and that the Company’s “failure to prudently address not only cyclical maintenance but also hazard trees should not result in ratepayers being required to pay for the significant level of storm damage that occurred” (Attorney General Brief at 107, 118, citing Exh. AG-HWS-1, at 15, 20-22 (electric)).

The Attorney General acknowledges that a storm of the magnitude of Winter Storm 2008 will inevitably cause damage, but asserts that the level of storm damage is dependent on the condition of the system and the vegetative maintenance in the years preceding the storm (Attorney General Brief at 108). The Attorney General argues that during the years 2001 through 2010, the Company did not adhere to the trim cycles that it adopted in 2001 (Attorney General Brief at 111, citing Exh. AG-HWS-2 (electric)). Rather, the Attorney General contends that, during this period, the Company trimmed its (1) 38 kV lines on a 13-year cycle, rather than on its planned five-year cycle, and (2) 4 kV lines on a 21-year cycle, rather than its planned eight-year cycle (Attorney General Brief at 111-113). The Attorney General asserts that the Company’s trimming program was narrowly aimed at achieving certain Department service quality targets, but left major parts of the system in poor condition (Attorney General Brief at 109).

Further, the Attorney General argues that the Company’s failure to expend amounts budgeted for transmission and distribution tree trimming during eight of the last ten years also indicates that the Company acted imprudently regarding tree trimming (Attorney General Brief at 113, citing Exh. AG-HWS-3 (electric)). The Attorney General asserts that the Company failed to comply with its own policy for vegetative maintenance (Attorney General Brief at 111). The Attorney General further argues that the Company's claim that its past vegetation management activities had no effect on the level of damage during the Storm is inconsistent with its proposal to increase its spending on the maintenance program to minimize problems with tree contacts and improve reliability (Attorney General Brief at 110, citing Exh. AG-HWS-1-Rebuttal at 14 (electric)).

The Attorney General contends that the Company's failure to adhere to its planned tree trimming cycles is exacerbated by its hazard tree removal program, or what the Attorney General describes as the Company's lack of a hazard tree removal program (Attorney General Brief at 113). The Attorney General states that the Company's Storm consultant identified whole trees or portions of trees located outside the normal trim zone hazard trees as the primary cause of damage during the Storm, while the ECI Report identified hazard trees as the largest contributing factor to poor reliability performance in general (Attorney General Brief at 114, citing Exhs. AG-10-44 (electric); AG-10-45 (electric); AG-10-52 (electric); Unitil-EC/AP-2, at 1-6 (electric)). The Attorney General argues that, based upon the importance of hazard trees as a contributing factor to Storm damage, the Company acted imprudently by failing to have a hazard tree component in its vegetation-control work plan (Attorney General Brief at 114, citing Exh. AG-HWS-1, at 22 (electric)).

Further, the Attorney General notes that although ECI proposes that the Company expend $780,000 annually just for hazard tree work, the Company's spending for both normal tree trimming and hazard tree work over the past ten years has only averaged approximately $300,000 per year (Attorney General Brief at 114, 116). The Attorney General argues that if the Company had removed hazard trees and overhanging branches as part of a $1.4 million annual maintenance program in the five years preceding Storm, those branches and trees would not have been able to damage the Company's system (Attorney General Brief at 117-118).

The Attorney General asserts that its review of 96 photographs of Storm damage "indicates that trees appear to be in close proximity to conductors and that where there were downed lines, the cause was overhanging branches as well as trees that may have been out of the clearing distance" (Attorney General Brief at 119, citing Exhs. AG-HWS-1, at 22 (electric); AG-10-1 (electric)). The Attorney General estimates that, based upon review of the photographs, the lack of tree trimming and hazard tree work contributed to 25 to 30 percent of the Storm damage (Attorney General Brief at 119, citing Tr. 18, at 2478-2480).

The Attorney General argues that the Company makes several inconsistent claims about its vegetation management program in existence prior to the Storm (Attorney General Brief at 120). First, the Attorney General claims that the Company asserts that its vegetation management program was reasonable and in accordance with industry standards and practices, but then asserts that there are no such standards and practices (Attorney General Brief at 120). Second, the Attorney General alleges that although the Company claims that it has always had a hazard tree program, its own experts state that the Company has not had a formal and comprehensive hazard tree removal program in place in the past (Attorney General Brief at 120, citing Exh. AG 13-3 (electric)).[23] Finally, the Attorney General contends that although the Company claims that $1.48 million of spending annually on vegetation management is necessary going forward (compared to an average of $300,000 per year over the past ten years), it also asserts that even if it had spent at that level prior to the Storm, the impact of the added spending would have been negligible (Attorney General Brief at 120). The Attorney General asserts that the Company's suggestion that increased trimming maintenance and an actual hazard tree program in the years preceding the Storm would have had a negligible impact on Storm costs is contrary to common sense (Attorney General Brief at 121).

To account for the excessive damage that resulted from the Company's imprudent vegetation management practices, the Attorney General recommends disallowing the difference between what she argues the Company should have spent on vegetation maintenance during the years 2003 through 2007 and what it actually spent (Attorney General Brief at 119-121). Using ECI's recommendations for annual spending on cyclical trimming for the Company's proposed VMP for which the Company is seeking approval (see Section X.O below) as the basis for what the Company was required to spend during those years, the Attorney General recommends disallowing $3,904,969 for what she considers to be the Company's imprudent vegetation management practices (Attorney General Brief at 119-121, citing Exh. AG-HWS- 1, at 13 (electric)).

[23] The Attorney General contends that the Company's witness subsequently "flip-flopped"by stating that the recommended hazard tree program is comparable to the Company's hazard tree removal prior to 2008 (Attorney General Brief at 120, citing Exh. Unitil-TPM/KES/RLF-Rebuttal- 1, at 17-18 (electric)).

(C) Storm Planning and Preparation

Additionally, the Attorney General asserts that the Company's poor storm planning and preparation resulted in higher costs for contractor labor (Attorney General Brief at 123). She contends that proper planning could have: (1) allowed the Company to establish agreements with contractors for responding to storm outages at negotiated rates, thereby avoiding having to "take what it could get" for labor and being charged in most instances at double-time rates; (2) allowed the Company to schedule contactors so that they did not work in excess of 16 hours per day;[24] and (3) reduced the travel time incurred for crews coming in to assist in the restoration (Attorney General Brief at 123). Further, the Attorney General argues that proper planning could have reduced the actual damage, because conductors become more susceptible to damage as the length of time they are under stress from previously-downed wires or trees increases (Attorney General Brief at 123).

The Attorney General asserts that the Company has not demonstrated that the Storm costs are reasonable and prudent (Attorney General Brief at 129). She contends that the Department should reduce the Company's proposed level of cost recovery by $2,011,153 to remove costs incurred as the result of the Company's improper planning (Attorney General

24 The Attorney General provides what it asserts is a "small sample of some, but not all" time sheets for crews that worked between 16 1/2 and 19 hours per day (Attorney General Reply Brief at 12, Exh. A).

Brief at 128-129). The Attorney General states that in order to derive what she considers to be a reasonable adjustment, she compared the Company's restoration cost of $30,250 per mile of wire in its service territory to WMECo's restoration cost of $4,625 per mile of wire in its service territory to determine the amount of this adjustment (Attorney General Brief at 128). Based upon the significant difference in costs of restoration per mile of wire between the Company and WMECo, the Attorney General asserts that a 30 percent adjustment to the Company's proposed recovery of deferred Storm costs is reasonable, which equals $2,011,153 (Attorney General Brief at 128).

(D) Economic and Other Losses within Fitchburg Service Territory

The Attorney General argues that the Department should consider the physical, mental, personal, and economic losses of the Company's customers when determining the amount of recoverable Storm costs, whether the Company should be allowed a carrying charge on those costs, and the term over which the Company should recover the Storm costs (Attorney General Reply Brief at 14-15). The Attorney General asserts that, based upon lost retail sales and manufacturing activity, the City of Fitchburg alone suffered economic losses of $2.3 million per day, or $13.8 million for the six-day average that customers were without service (Attorney General Reply Brief at 14-15, citing Exh. AG-3 (electric); Tr. 20, at 2669-2670). Because the City of Fitchburg represents only two-thirds of the Company's service territory, the Attorney General asserts that the total service territory suffered economic losses in excess of the $15.1 million (Attorney General Reply Brief at 14-15). The Attorney General argues that, in making decisions on the Company's proposal, the Department "should remember that customers have already paid once for the [S]torm" (Attorney General Reply Brief at 15).

b. Fitchburg

i. Introduction

The Company contends that the Department's determination on Storm cost recovery must ultimately rest on substantial evidence developed through an adjudicatory proceeding, and not "on generalities, 'logical' conclusions that contradict record evidence, pre-judgments or aromas" (Company Brief at 16, citing G.L. c. 164, § 76, 94; G.L. c. 30A, § 11; Tr. 16, at 1991). The Company states that the Department should reject the Attorney General's recommendation to disallow approximately one-half of the Company's incurred Storm costs (and spread the recovery of the remaining amount over a ten-year period), arguing that this level of disallowance (1) does not represent a "justified disposition" of its Storm-related costs, and (2) would undermine the Company's financial integrity and its ability to institute "meaningful and lasting changes in its operations and storm-response capabilities" (Company Reply Brief at 3-4). The Company asserts that, instead, the evidentiary record in this proceeding supports a recovery of $11,592,962 in Winter Storm 2008 costs (Company Brief at 16-17).

ii. Documentation of Storm Costs

The Company maintains that it has provided detailed transactional reports of Storm charges that demonstrate that the majority of the approximately $11.6 million in Storm costs were payments to contractors (Company Brief at 28). The Company argues that documentation supports the Storm costs (Company Brief at 29). Contrary to the Attorney General's claim, the Company contends that it has properly reduced the Storm costs by $271,003 for amounts billed to Verizon for tree and pole-related work during the Storm (Company Brief at 30). Additionally, the Company contends that it paid the same rates for mutual assistance crews as those paid by other utilities, including those released by National Grid late in the restoration process (Company Brief at 29). Those rates, it argues, were consistent with EEI's governing principles for mutual assistance and pertinent labor contracts (Company Brief at 29). Additionally, it contends that it provided a summary by vendor of the information used to validate invoices, contractor rate sheets, and samples of field time sheets and contractor time sheets (Company Reply Brief at 23, citing RR-DPU-37).

The Company contends that its Storm-related repair costs are in line with those incurred by WMECo and National Grid (Company Brief at 29, 30). It argues that, for example, its total repair cost divided by the number of feet of distribution wire replaced was $78, compared to WMECo's cost of $119 and National Grid's cost of $78 per foot (Company Brief at 29, citing Exh. Unitil-MJ-4, at 3 (electric)). Additionally, the Company contends that its total cost per crew day was $7,809, compared to $7,417 for WMECo and $8,876 for National Grid (Company Brief at 29, citing Exh. Unitil-MJ-4, at 3 (electric)).

iii. Effect of Performance on Storm Costs

(A) Historic Vegetation Management Practices

The Company argues that, because the Department was unable to establish in D.P.U. 09-01-A a clear, direct correlation between the Company's vegetation management practices and the resulting Storm damage, evidence of such a correlation must be developed in the instant proceeding to support a finding that the Storm-related repair costs were increased as a result of the Company's actions (Company Brief at 17, citing D.P.U. 09-01-A at 159-160). The Company asserts that the Attorney General failed to establish evidence of this correlation because her witnesses either (1) erroneously took it as a matter of logic that the Company's tree trimming practice had to have contributed to the damage, or (2) assumed that a correlation exists based on the Department's findings in D.P.U. 09-01-A (Company Brief at 17-18, citing Exhs. AG-HWS- 1, at 14 (electric); AG-DO-CF-1, at 18 (electric); AG-JC- 1, at 20 (electric)).

The Company contends that the record shows that the Storm was of "a severity that would cause catastrophic damage irrespective of a company's maintenance practice," arguing that (1) severe ice storms are ranked on a scale with tornados with respect to catastrophic damage for electric utilities, and (2) catastrophic tree damage occurs when the ice exceeds one-half of an inch (Company Brief at 18-19, citing Tr. 19, at 2574).[25] The Company maintains that ice accumulation during the Storm ranged from one-half to three-quarters of an inch within the Fitchburg service territory, and that along the New Hampshire border, where the Town of Ashby, Massachusetts is located, the ice accumulation ranged from an inch to an

25 The Company argues that several state public utility commissions, including the Kentucky Service Commission, have recognized that one-half inch of ice accumulation on wires represents the threshold of catastrophic damage (Company Initial Brief at 19, citing Assessment of the Electric Utilities Response to the February 2003 Ice Storm, Kentucky Service Commission at 3 (February 6, 2004).

inch and one-half (Company Brief at 19). The Company asserts that in a storm in which ice loading exceeds one-half inch, "the damage that occurs is so severe and so widespread that the damage could not be avoided by achieving clearing of 15 feet from side to side of the conductor and by performing a routine level of hazard tree work along tree trimming routes, even if those activities were consistently performed on a relatively short trim cycle" (Company Brief at 19-20, citing Tr. 19, at 2575).[26]

The Company cites to the experience in Lunenburg to demonstrate that historical tree trimming cycles did not affect Storm damage (Company Brief at 20). According to the Company, it trimmed approximately 70 percent of the two overhead circuits that serve Lunenburg within the five-year period, 2004 through 2008 (Company Brief at 20, citing Exh. DPU-22-17 (electric)). Yet, when National Grid crews arrived in the Fitchburg service territory on December 21, 2008, they initially devoted the majority of their crew time to restoring power to Lunenburg customers located on the same circuits that the Company recently had trimmed (Company Brief at 20). Moreover, the Company states that, if a greater level of historical vegetation management would have reduced Storm damage, then the Company should be expected to have incurred a greater amount of vegetation clean-up costs proportionately than other electric companies affected by the Storm (Company Brief at 18, 20). The Company asserts that, to the contrary, the record shows that its cost of Storm-related

26 The Company cites to the Attorney General's testimony in D.P.U. 09-01-A that normal tree trimming practices that are designed to maintain a clearance between the wires and limbs "do not help much during ice storms" (Company Reply Brief at 9, citing D.P.U. 09-01-A, Tr. 3, at 605).

vegetation management contractors comprised only five percent of its total Storm expense, compared to 13 percent of National Grid's total expenses (Company Brief at 20, citing Tr. 18, at 2389-2394).

The Company argues that its proposal to substantially increase its vegetation management program from past practices is not indicative that its past practices materially contributed to Storm damage and costs (Company Brief at 20). The Company asserts that its proposed program is not intended to be a "storm hardening" program, but instead is intended to improve its performance with respect to non-storm reliability standards established by the Department (Company Brief at 21, citing Exh. AG-8-30 (electric); Tr. 10, at 1300; Company Reply Brief at 17-18). The Company contends that it was not unreasonable for it to rely on non-storm reliability standards to guide its vegetation management activities (Company Reply Brief at 20). The Company further asserts that the Attorney General dismisses the importance of the Department's service quality measurements (Company Reply Brief at 20).

The Company further asserts that the record does not support the Attorney General's contention that the trees that fell on lines from outside the trim zone were all "hazard" trees that would have been removed had the Company pursued a more aggressive level of hazard tree removal (Company Brief at 21-22, citing Attorney General Brief at 113-114). The Company states that ECI concluded that over 80 percent of all trees on the Fitchburg system have a high to moderate susceptibility to ice damage (Company Brief at 22, citing Exh. Unitil-EC/AP-Rebuttal-1, at 6 (electric)). Further, the Company argues that ECI concluded that these trees, many of which are located outside the normal trim zone, tend to fall during ice storms even when they are healthy and without major defects (Company Brief at 22, citing Exh. Unitil-EC/AP-Rebuttal-1, at 6 (electric)). The Company asserts that it is these healthy trees, rather than dead trees, that cause the greatest damage in ice-storm events, including the Winter Storm 2008 (Company Brief at 22-23, citing Tr. 19, at 2529, 2613-2617). The Company adds that the concept of addressing hazard trees as a discrete and focused program is a relatively new concept that few utilities have addressed in their vegetation management practices (Company Reply Brief at 19). The Company contends that, consistent with historical industry practice, its hazard tree work was performed in conjunction with its tree trimming activities (Company Reply Brief at 15, 19).

The Company asserts that the 96 photos relied upon by the Attorney General "exactly illustrate the dynamic that the Company has attempted to explain throughout this proceeding, which is that the greatest damage was caused by healthy trees and tree limbs bending or falling from outside the trim zone onto the Company's facilities" (Company Brief at 23, citing Exh. AG-10-1 (electric)). The Company asserts that this point is demonstrated by photographs of the number of large limbs shearing off directly from the trunk, the missing tops of trees and the extremely low bow of healthy trees curving over the conductors (Company Brief at 23). It contends that had the low, overhanging trees been trimmed prior to the Storm, there would have been less material to remove to perform repairs, but that repairs would still have been needed because the damage was ultimately caused by whole parts of the tree that would not have been affected by tree trimming activities (Company Brief at 23).

Finally, the Company states that there is no basis for the Attorney General's proposed cost disallowance of $3,904,969 (approximately equal to 25 percent of the Company's total repair costs), which is the amount the Attorney General determined the Company under-spent in vegetation management during the years 2003 through 2007 (Company Brief at 23). The Company asserts that such a disallowance of repair costs would have to be backed by facts that show that the incurred costs would not have been needed but for the Company's historic tree trimming and hazard tree activities (Company Reply Brief at 5-6). The Company argues that the Attorney General has not put forth any study, analysis, or other basis to support that this level of repair costs were due in whole or in part to tree limbs that would have been trimmed, or hazard tree work that would have been performed had the Company met its cyclical tree trimming cycles (Company Brief at 23-24).

(B) Storm Planning and Preparation

The Company argues that the assertions made by the Attorney General regarding the impact of alleged deficiencies in the Company's Storm response on its restoration costs are directly rebutted by the record (Company Brief at 24-25). With respect to the Attorney General's claim that the Company should have done more to obtain crews prior to the Storm, the Company asserts that (1) given the severity of the Storm, it would have been very difficult to secure the number of contractor crews ultimately needed to complete repairs, and (2) even if it had been able to identify crews that were not already committed to other utilities, it would have had to start paying those crews at storm duty rates from the time they were hired to stand by on an around-the-clock basis (Company Brief at 24-25; Company Reply Brief at 22). The Company asserts that, although following this course of action may have served to shorten the duration of the restoration, it would have increased the cost of the restoration effort (Company Brief at 25, citing Exh. Unitil-TPM-KES-RLF-Rebuttal-1, at 21-23 (electric)).

The Company similarly disputes the Attorney General's claim that the Company improperly paid different rates for various contactors, and paid the majority of contractors at double time for all hours that they worked (Company Brief at 25-26). The Company maintains that it is obligated to abide by the collective bargaining agreements that govern the reimbursement of contractor crews during storm events, and that virtually all of these agreements require the payment of double time for storm duty (Company Brief at 25-26, citing Exh. Unitil-TPM-KES-RLF-Rebuttal-1, at 27-28 (electric)). The Company states that (1) national labor organizations such as the International Brotherhood of Electrical Workers and the Utility Workers Union of America have standard protocols for the payment of storm duty, which apply from the point of dispatch (including mobilization and demobilization time), and (2) the costs for utility crews obtained through the mutual aid process are dictated by the agreements in place with those utilities (Company Brief at 26). The Company maintains that standard utility practice dictates that all crews work 16 hours on and eight hours off,[27] and that

[27] The Company states that the time sheets presented by the Attorney General show only minor variations to the 16-hour work day, and that these variations occur because if crews are in the middle of a job, they do not leave because they reach the 16-hour threshold (Company Reply Brief at 21).

the applicable rate applies to all hours, with no ability to negotiate any kind of rate discount (Company Brief at 26; Company Reply Brief at 21). The Company asserts that, as such, it did not pay any more than necessary for its crews, and no more than would be typical for other utilities operating under the same circumstances (Company Brief at 26-27, citing Exh. Unitil-TPM-KES-RLF-Rebuttal-1, at 28-30 (electric)).

The Company argues that the Department should reject the Attorney General's recommended cost disallowance of $2,011,153, based on her comparison of the Company's Storm restoration costs per total distribution circuit mile to those of WMECo (Company Brief at 27). The Company contends that the Attorney General's analysis is flawed because it assumes that the amount of damage on the WMECo system was proportional to the amount of damage on the Fitchburg system (Company Brief at 27-28). The Company states all four towns that it serves were "equally and completely" affected by the Storm (Company Brief at 27). In contrast, the 59 cities and towns served by WMECo were not equally affected by the Storm, and that municipalities in the western and southern portions of WMECo's service territory may not have experienced any effects from the Storm (Company Brief at 27-28). The Company maintains that the record shows that, despite the fact that WMECo's service territory encompasses seven times the number of circuit miles as Fitchburg's, WMECo replaced substantially fewer miles of distribution wires as a result of the Storm (132,166 miles) that did the Company (192,729 miles) (Company Brief at 28). In addition, the Company asserts that the WMECo Storm costs used by the Attorney General do not include its full restoration costs, as it appears that WMECo did not include the cost of 598 transformers it replaced because of the Storm (Company Brief at 27, citing Exh. Unitil-MJ-4, at 2-3 (electric)).

(C) Economic and Other Losses within Fitchburg Service Territory

The Company disputes the Attorney General's assertion that the Department should take into consideration the lost economic activity experienced within the Fitchburg service territory (Company Reply Brief at 23). First, the Company argues that the Attorney General's analysis of economic loss is misguided and inaccurate because hundreds of communities in the Commonwealth experienced unfortunate economic losses as a result of the Storm, and the fact that customers in the Fitchburg service territory were affected is not fully attributable to the Company (Company Reply Brief at 24). Further, the Company asserts that the Attorney General does not take into account the fact that approximately 23 percent of customers in the City of Fitchburg lost their service because of an outage on the National Grid transmission lines that serve the Fitchburg system, and had their service restored once National Grid repaired those lines (Company Reply Brief at 24). Finally, comparing its 14-day total restoration period to the ten-day total restoration period in National Grid's service territory, the Company asserts that it would not have been able to restore service much faster (Company Reply Brief at 24-25).

3. Standard of Review

The Department stated in D.P.U. 09-01-A that we would review the prudence of the Company's Storm-related costs to determine whether recovery of those costs is warranted, and that we would disallow any imprudently-incurred costs. D.P.U. 09-01-A at 196. The Department may deny costs that are directly attributable to imprudent management decisions. Massachusetts-American Water Company, D.P.U. 95-118, at 46, 50, 51, 57 (1996); Boston Gas Company, D.P.U. 93-60, at 28-30 (1993); Boston Edison Company, D.P.U. 92-1A-A at 17 (1993); Cambridge Electric Light Company, D.P.U. 91-2C-1, at 17-18 (1993); Natural Gas Shortage, D.P.U. 555-C at 258-259 (1983); Natural Gas Shortage, D.P.U. 555, at 4-5 (1982). Imprudently-incurred costs are those increased costs that a company would not have incurred but for imprudent management decisions. D.P.U. 95-118, 46, 50, 51, 57; D.P.U. 93-60, at 28-30; D.P.U. 92-1A-A at 17; D.P.U. 91-2C-1, at 17-18; D.P.U. 555-C at 258-259; D.P.U. 555 at 4. In conducting a prudence review, the Department may not interfere with reasonable company judgments made in good faith and within the limits of reasonable discretion. Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 09-09, at 38 (2009); D.P.U. 555-C at 16. The Department is required, however, to determine whether the company's actions, based on all it knew or should have known at the time, were reasonable and prudent in light of the then-existing circumstances. D. P.U. 09-09, at 38; Milford Water Company, D.P.U. 08-5, at 12-13 (2008), citing D.P.U. 93-60, at 24-25; Western Massachusetts Electric Company, D.P.U. 85-270, at 22-23 (1986); Boston Edison Company, D.P.U. 906, at 165 (1982). A determination of reasonableness and prudence 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 judgment of the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983).

4. Analysis and Findings

a. Introduction

The Department's precedent on prudence reviews requires that in order for us to disallow costs we must identify increased costs that are directly attributable to an imprudent management decision by a company. See D.P.U. 95-118, 46, 50, 51, 57; D.P.U. 93-60, at 28-30; D.P.U. 92-1A-A at 17; D.P.U. 91-2C-1, at 17-18; D.P.U. 555-C at 258-259; D.P.U. 555 at 4. In the sections below, the Department addresses: (1) two adjustments based upon a discrepancy in deferred costs and application of a retroactive Storm pay policy for salaried Company and USC employees; (2) whether the remaining Storm costs are sufficiently documented to demonstrate that the expenses are accurately categorized as Storm costs and therefore eligible for recovery; (3) the extent to which the Company's deficient performance in its historic vegetation management practices and storm planning and preparation resulted in it incurring higher Storm restoration and repair costs; and (4) the ratemaking treatment to be provided to recoverable Storm costs.

b. Discrepancy in Deferred Costs

In 2009, the Department approved deferral accounting treatment for $11,515,848 in Storm-related expenses for review in the Company's next rate case. Fitchburg Gas and Electric Light Company d/b/a Unitil, D. P. U. 09-61, at 14 (2009). The Company, however, seeks recovery of $11,592,962 in deferred incremental storm restoration and repair expenses. The Company states that the reason for the discrepancy between what the Department approved for deferral and what the Company requests to recover is a change to the emergency restoration costs (Exh. DPU-1-9 & Att. (electric)).

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 (1988); see also D.P.U. 88-171, at 29-30. A company may, however, petition the Department to allow it to defer the accounting treatment of expenses incurred prior to the test year. See, e.g., D.P.U. 09-61; 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. D.P.U. 04-77, at 5, citing D.P.U. 93-229, at 7-8. Granting a deferral does not constitute a finding that the subject expenses are reasonable or that they can be recovered from ratepayers. D.P.U. 93-229, at 4, citing Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80, at 40 (1991).

The Company incurred Storm-related costs between December 11, 2008, and January 24, 2009 (Exh. Unitil-MJ-3, at 3, 4 (electric)). The Company has not explained why the Storm-related costs for which it seeks recovery varied from the $11,515,848 approved for deferral in D.P.U. 09-61 (Exh. DPU-1-9 & Att. (electric)). It also has failed to demonstrate when it incurred the additional cost (Exh. DPU-1-9 & Att. (electric)). Had the Company demonstrated that it incurred the additional cost in January 2009, those expenses would have been incurred during the test year and would be eligible for possible inclusion in cost of service. See D.P.U. 88-67, at 143-145. If, however, the change in cost is attributable to a correction in Storm costs that the Company incurred during December 2008, that cost would be a pre-test year expense that is ineligible for recovery because the Department did not approve deferral accounting treatment for that additional cost. See D.P.U. 09-61, at 17; Boston Gas Company/Essex Gas Company/Colonial Gas Company d/b/a National Grid, D.P.U. 10-55, at 303 (2010).

The Department's Order in D.P.U. 09-61 contained no provision to adjust the $11,515,848 approved for deferral. D.P.U. 09-61, at 14. Because the additional cost has not been approved for deferral and the Company has not demonstrated that it incurred the cost during the test year, the Department disapproves recovery of the difference between the total amount of the deferred expenses for which the Company requests recovery, $11,592,962, and the amount approved by the Department for deferral accounting treatment, $11,515,848, resulting in a disallowance of $77,114.

c. Storm Pay for Salaried Employees

The Company seeks recovery of $111,560[28] in overtime pay for salaried Company and USC employees who worked during the Storm restoration period (RR-DPU-15). According to the Company, it has historically handled storm pay for salaried employees on a case-by-case basis (Exh. DPU-1-7, Att. 1 (electric)). Following Winter Storm 2008, the Company adopted a policy to pay salaried employees for overtime during emergency storm restoration periods, but made the effective date of the policy retroactive to December 1, 2008 (Exh. DPU-22-6 (electric)).

The Company states that it adopted the storm compensation policy[29] for salaried employees because Winter Storm 2008 required some salaried employees to work around the clock, while the crews these employees supervised earned pay at double time rates (Exh. DPU-1-7, Att. 1 (electric)). The Company points to a February 2008 compensation survey, which determined that 14 of the 16 companies surveyed pay storm restoration overtime to salaried employees (Exh. DPU-1-7, Att. 1 (electric)). Of the 14 companies, eleven paid salaried employees at straight time rates and three paid salaried employees at either a fixed rate

[28] The record contains several inconsistent statements about the amount of overtime pay for salaried employees during the Storm: (1) $101,342.80; (2) $97,254.98; and $111,560.92 (Exhs. Unitil-MJ-3, at App. 2, at 2 & App. 3, at 1 (electric); DPU-1-7, Att. 1 (electric); RR-DPU-15). The Company's most recent update to overtime pay for salaried employees, however, is $111,560.92 (RR-DPU-15).

[29] The Company describes the policy of paying salaried employees for time beyond their normal hours during the Storm as a storm pay policy rather than an overtime compensation policy (Exh. DPU-22-6 (electric)). The Company's consultant, however, describes this category of costs as "overtime" (Exh. Unitil-MJ-3, at 5-6 (electric)).

or a premium rate (Exh. DPU-1-7, Att. 1 (electric)). The Company adopted a policy that paid salaried employees overtime at straight time rates, with a limit of eight hours per day of overtime on a regular workday and 16 hours on a holiday or weekend (Exh. DPU-1-7, Att. 1 (electric)).

In contrast to overtime pay for union employees paid at an hourly rate, overtime pay for salaried employees performing storm duties is a discretionary expense for the Company (Exhs. Unitil-MJ-3, at 5 (electric); DPU-1-7 (electric); DPU-22-6 (electric)). Moreover, the Company adopted the storm pay policy for salaried employees only after Winter Storm 2008 (Exh. DPU-22-6 (electric)). While the Department acknowledges the Company's efforts to provide some measure of pay equity for salaried employees, we disapprove of the retroactive application of the storm pay policy for salaried employees in this instance. Rather, the Department finds that shareholders should bear the cost of the storm pay for salaried employees in this particular case.[30] Accordingly, we disallow $111,560 of the Storm expenses.

d. <u>Documentation of Storm Costs</u>

The Department agrees with the Attorney General that the Company's consultant performed an incomplete review of the Storm costs. The Company's consultant (1) initially submitted limited documentation to support the accuracy and reasonableness of the Storm costs, (2) verified certain costs through undocumented conversations with the Company,

30 It is within the Company's discretion whether to continue applying the Storm-pay policy. Recovery of any future costs incurred as a result of this policy will be determined in future proceedings.

(3) failed to independently verify contractor rates listed on invoices, and (4) relied on insufficient documentation to verify certain costs, including the PECo invoice, for which the Company initially had no supporting documentation (Exhs. Unitil-MJ-3, at 7 & App. 1–7 (electric); DPU-1-2, Att. 13, at 49-58 (electric); Tr. 9, at 1016-1017, 1058-1060, 1079-1080, 1088-1089; Tr. 10, at 1312-1314, 1331). The Company's consultant emphasized that he did not perform an audit of these costs (Tr. 9, at 1020, 1065, 1073, 1080, 1098-1099). Further, he admitted that an audit would entail a more detailed review, seek the production of additional documentation to support costs, and require that notes and workpapers be retained (Tr. 9, at 1064, 1098-1099). Given the significant costs for which the Company seeks recovery, and the Company's poor performance during the Storm, the Department expected the Company to submit a more thorough review of the Storm costs to support the requested recovery.

During the course of this proceeding, however, the Company submitted additional evidence that demonstrates that the costs for which the Company seeks recovery were incurred during the restoration period, are accurately categorized as Storm costs, and are supported by documentation (Exhs. DPU-1-2, Atts. 1-14 (electric); DPU-17-1 & Att. (electric); DPU-22-1 (electric); DPU-22-12 (electric); DPU-22-13 (electric); DPU-22-14 (electric); DPU-24-10 (electric); DPU-24-11 (electric); DPU-24- 12 (electric); DPU-24- 15, Atts. 1-3 (Rev.) (electric); RR-DPU-38 & Att. 1-2). The vast majority of the Storm costs are for contractor and related services (Exh. Unitil-MJ-3, at 4 (electric)). Documentation supporting those costs include crew time sheets or field time sheets, rate sheets that denote applicable crew rates or other information that demonstrate blended rates for contractors, and other supporting information (Exhs. DPU-1-2, Atts. 1-14 (electric); DPU-24-16 (electric); RR-DPU-37, Att. 1). Additionally, the Company located and submitted time sheets and other supporting documentation for certain invoices that initially lacked such documentation, including the PECo invoice (Exhs. DPU-24-10 (electric); DPU-24-11 (electric); DPU-24-12 (electric); DPU-24-15, Atts. 1-3 (rev.) (electric)). Further, the Company provided an acceptable explanation of its process for reviewing and approving contractor invoices (RR-DPU-37, Att. 2).

The Department also concludes that the Company has submitted sufficient information to demonstrate that non-contractor costs are accurate and were incurred during the Storm period (Exhs. Unitil-MJ-3, Apps. 2-7 (electric); DPU-1-8, Att. (electric); DPU-9-1 & Att. (electric); DPU-9-3, Att. (electric); DPU- 17-3 (electric); DPU-24- 1, Atts. 1-3 (electric); DPU-24-17, Att. (electric); DPU-24-18 (electric); RR-DPU-39; RR-DPU-46; RR-DPU-47; RR-DPU-48). Additionally, the Company demonstrated that it reduced its requested Storm costs by $271,003 to recognize Verizon’s share of tree-related Storm restoration work (Exh. DPU-24-5 (Supp.)). Finally, based upon standard utility practice in retaining emergency crews, the difficulty the Company had in retaining crews over the holiday period, and extensive damage to the Company’s distribution system, the Department finds that the Company appropriately paid contractor crews emergency storm rates for work performed in January 2009 (Exh. Unitil-MJ-3, at 4 (electric); Tr. 9, at 1082-1085, 1093-1094).

The Department's finding that the Storm costs are supported by sufficient documentation, however, does not demonstrate that those costs were reasonably and prudently incurred. Similarly, the Company's comparison of its Storm costs per crew day and repair cost per foot of distribution wire replaced with similar costs incurred by WMECo and National Grid does not in and of itself demonstrate that the costs were reasonable.[31] Rather, as discussed below, the Department must evaluate whether the Company incurred additional costs as a result of imprudent management decisions during the restoration period. See D.P.U. 95-118, 46, 50, 51, 57; D.P.U. 93-60, at 28-30; D.P.U. 92-1A-A at 17; D.P.U. 91-2C-1, at 17-18; D.P.U. 555-C at 258-259; D.P.U. 555 at 4. If the Company incurred additional costs as a result of imprudent management decisions, those costs will be disallowed.

[31] The Department has not yet determined that National Grid and WMECo reasonably and prudently incurred their respective Winter Storm 2008 costs. National Grid recovered approximately $28.8 million of its Winter Storm 2008 costs from its storm reserve fund. See Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 09-39, at 198, 209-210 (2009). The Department allowed National Grid to begin recovering $30.1 million in its remaining Storm costs, subject to further review and reconciliation and demonstration by National Grid that those costs were reasonably and prudently incurred. D.P.U. 09-39, at 211-212. Additionally, the Department allowed WMECo to begin recovering its Winter Storm 2008 costs, also subject to further review, reconciliation, and demonstration by WMECo that those costs were reasonably and prudently incurred. Western Massachusetts Electric Company, D.P.U. 10-70, at 195-196 (2011). On April 1, 2011, to support recovery of its remaining Storm costs, National Grid submitted a third party audit. That matter has been docketed as Massachusetts Electric Company/Nantucket Electric Company d/b/a National Grid, D.P.U. 11-56, and is under review. WMECo has not yet made a filing to demonstrate that its costs were reasonably and prudently incurred.

e. Effect of Performance on Storm Costs

i. Introduction

In D.P.U. 09-01-A at 159, the Department concluded that the Company underfunded its vegetation management budget and fell behind its prescribed tree trimming schedule in the years preceding the Storm. The Department stated that, while the majority of damage that occurred in the Storm can be attributed to falling trees and branches, "[t] he record contains insufficient data . . . to distinguish damage caused by the Company's insufficient tree trimming and removal of hazard trees from damage caused by trees located outside the Company's control (e.g., outside the Company's right of way or where property owners do not give consent to trim)." D. P. U. 09-01-A at 159-160. The Department determined that, while we could not draw a clear, direct correlation between the Company's vegetation management practices and the resulting storm damage, the Company's vegetation management activities contributed to storm damage on its distribution system. D.P.U. 09-01-A at 160.

The Department will not revisit in this proceeding our findings in D.P.U. 09-01-A regarding the Company's failure to adhere to its tree trimming cycles. Instead, our investigation focuses on the extent to which the Company's failure in this regard contributed to Storm damage, and whether such failures led the Company to incur higher costs to repair damage and restore service to its customers.

ii. Historic Vegetation Management Practices

The Attorney General puts forth three factors in support of her assertion that the Company's failure to address vegetation management was the major factor contributing to

Storm costs. First, she cites to the Company's failure to adhere to its planned tree trimming cycles and implement a formal hazard tree program during the years preceding the Storm. (Attorney General Brief at 111-113). The Department fully investigated the Company's vegetation management practices during years 2004 through 2008 in D.P.U. 09-01-A, and determined that the Company was 18 to 21 months behind on its distribution system tree trimming at the end of 2008. D.P.U. 09-01-A at 151. The Attorney General examined the Company's tree trimming practices between the years 2001 through 2010, and concluded that the Company's actual trimming was significantly less than what was required to achieve its adopted tree trimming cycles (Exh. AG-HWS-1-Rebuttal at 5-6 (electric)). The evidence put forth by the Attorney General in this proceeding confirms our conclusion in D.P.U. 09-01-A regarding the Company's failure to adhere to its tree trimming schedule. That evidence, however, does not allow the Department to distinguish between Storm damage caused by the Company's insufficient vegetation management practices and damage caused by trees located outside of the Company's control. See D.P.U. 09-01-A at 158-160.

Second, the Attorney General contends that the Company's proposed significant increase in spending on vegetation management demonstrates that its historic spending level was a major contributor to Storm costs (Attorney General Brief at 114-118). The Department agrees that the Company's proposal to increase spending is an indication that the Company's past vegetation management practices were deficient. Because of the severe nature of the Storm, however, in particular the ice accumulation that ranged from one-half inch to up to one and one-half inches in the Company's service territory, it is not clear to what extent the Company's adherence to its planned trimming cycles (including the removal of hazard trees) would have resulted in less damage (Tr. 19, at 2574-2575, 2614-2617). See also D.P.U. 09-01-A at 19, Exh. FGE-2, Vol. I, at 14.[32] As such, we cannot draw any conclusions regarding the extent to which the Company's historic spending levels on vegetation management contributed to Storm damage.

Finally, the Attorney General relies on 96 photographs of damage provided by the Company, which she asserts demonstrate that overhanging branches and trees were in close proximity to down wires, to estimate that the Company's lack of tree trimming and hazard tree work contributed to 25 to 30 percent of the damage (Attorney General Brief at 119). The Department disagrees with the Attorney General on this matter. Based on our review of the photographs, we find that: (1) very few of the photographs appear to illustrate that the fallen branches that caused damage would have been removed had the Company sufficiently pursued its vegetation management plan (Exh. AG-10-1, Photos 058, 059, 066, 096 (electric)); (2) many illustrate damage to trees outside the Company's trim zone (Exh. AG-10-1, Photos 007–010, 013-015, 019, 024, 025, 027, 029, 030-033, 035, 038, 040, 047, 056, 057, 060, 062, 063, 069, 076, 078-080, 084-088, 090) (electric)); and (3) some of the photographs are inconclusive regarding whether the damage was caused by trees and branches inside or outside

[32] We acknowledge the subjective nature of photographs, as recognized by the Attorney General during hearings, and further that the submitted photographs capture only a portion of the damage incurred during the Storm (see Tr. 16, at 1973-1978).

of the Company's trim zone (see Exh. AG-10-1, Photos 001-006, 011, 012, 016-018, 020-023, 028, 032, 034, 036, 037, 039, 041, 043-055, 061, 064, 065, 067, 068, 070-075, 077, 081-083, 089, 091-095 (electric)). As such, we conclude that the photographs do not allow us to draw a direct correlation between the Company's vegetation management practices and the damage that occurred during the Storm. Further, because the photographs are selective and not representative of all the damages that occurred in the Company's service territory, we disagree with the Attorney General that the photographs demonstrate that 25 to 30 percent of Storm damages occurred due to overhanging branches and trees in close proximity to overhead wires (see Exhs. AG-10-1 (electric); AG-JC-1, at 19 (electric); Tr. 16, at 1976-1978, 2097-2098).

The Company makes three arguments to support that its historic vegetation management practices did not affect Storm damage. First, the Company cites to its experience in Lunenburg, which required the attention of the National Grid repair crews during their initial days in the Fitchburg service territory despite the fact that the Company had performed significant tree trimming on that town's overhead circuits in the five years preceding the storm, as demonstration of the lack of correlation between its historic vegetation management practices and the resulting storm damage (Company Brief at 20, citing Exh. Unitil-TPM-KES-RLF-Rebuttal- 1, at 19-20 (electric)). The Department disagrees. While the Company's experience in Lunenburg demonstrates that the Storm's severity was so significant as to cause damage even in areas where the Company's tree trimming activities were on schedule, it by no means establishes an overall disconnect between the Company’s vegetation management deficiencies and the resulting damage. Instead, it confirms the difficulty in drawing a direct correlation between the Company’s vegetation management activities and the resulting damage.

Second, the Company cites to a comparison of the percent of its total Storm costs that were comprised of tree-related activities (five percent) to that of National Grid (13 percent) as further demonstration that its vegetation management performance did not result in higher Storm damage, asserting that if its tree trimming performance in the years preceding the Storm resulted in higher costs, it would be in the form of costs associated with the clearing of fallen trees (Company Brief at 18-20). The Department reaches no such conclusion from this comparison. There are too many factors that may affect the underlying calculation for us to give the comparison much credence.

Finally, the Company cites to its review of the 96 photographs in support of its argument that the greatest damage was caused by healthy trees and tree limbs located outside of its trim zone, which would not have been affected by its trimming activities (Company Brief at 23). As discussed above, the Department finds that while the photographs provide a strong sense of the scope of the damage from the Storm, they are not conclusive regarding whether the damage was caused by trees and branches inside or outside of the Company’s trim zone (see Exhs. AG- 10-1 (electric); AG-JC- 1, at 19 (electric); Tr. 16, at 1976-1978, 2097-2098).

Based on the above, the Department concludes that neither the Attorney General nor the Company has presented evidence in this proceeding that allows us to establish a direct relationship between the Company’s deficient vegetation management practices in the years preceding the Storm, and the resulting Storm damage and costs. Therefore, the Department confirms our findings in D.P.U. 09-01-A that, while the Company’s practices contributed to Storm damages, we are unable to draw a direct correlation between those practices and the exact amount of the resulting costs.

The Attorney General proposes that the Department reduce the level of Storm-related costs that the Company can recover from its ratepayers by $3,904,969. The Attorney General’s figure is based on the difference between what the Company would have spent on vegetation management had it performed properly (using the ECI-recommended spending levels) and its actual expenditures (Attorney General Brief at 119-120). The Attorney General does not attempt to demonstrate that her proposed cost disallowance is directly attributable to increased costs that resulted from the Company’s poor vegetation management performance in years prior to the Storm, but contends that based on review of the photographs of Storm damage, the lack of tree trimming and hazard tree work contributed between 25 to 30 percent of the damage (Attorney General Brief at 119-120).

The Department precedent on prudence reviews requires us to find that Storm costs were directly attributable to an imprudent management decision in order to disallow such costs. See D.P.U. 95-118, 46, 50, 51, 57; D.P.U. 93-60, at 28-30; D.P.U. 92-1A-A at 17;

D.P.U. 91-2C-1, at 17-18; D.P.U. 555-C at 258-259; D.P.U. 555 at 4. The Department concludes that, although the Company's poor vegetation management before the Storm likely resulted in some level of increased costs, there is insufficient evidence in this proceeding to identify the exact level of Storm costs that were a direct result of the Company's deficiencies in this regard. Nor does the Department accept the Attorney General's proposal to deny costs by means of a proxy calculation. Therefore, there is no justification for disallowing deferred Storm costs on the basis of the Company's vegetation management practices. Instead, the Department finds that in light of the severe nature of the Storm, which would have resulted in the Company incurring significant Storm costs regardless of its performance, and the difficulty in identifying direct, correlative evidence that demonstrates that the Company's deficient Storm response increased the Storm costs, we account for the Company's mismanagement of its Storm response in the following areas: (1) the ratemaking treatment we apply to the recovery of those costs, including the amortization period over which the Company recovers costs and the application of carrying charges;[33] (2) the D. P. U. 09-01-A legal and consultant costs; (3) the retroactively awarded overtime pay for salaried employees who worked during the restoration period; (4) costs associated with Storm-related witnesses in this proceeding; (5) costs to address future storms (a storm fund); (6) management incentive compensation; and (7) the Company's ROE.

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[33] Although the Department cannot attribute all economic losses experienced in the Company's service territory to the Company's poor performance, as the Attorney General urges, we acknowledge that its poor performance exacerbated numerous customer difficulties during the Storm, and will consider this in establishing ratemaking treatment of allowable Storm costs. See D.P.U. 09-01-A at 9-17.

iii. Storm Planning and Preparation

In D.P.U. 09-01-A at 47, the Department found that the Company's failure to properly plan and prepare for storm events resulted in: (1) its inability to restore service to its customers in a timely manner; (2) its failure to communicate accurate and useful information to the public; and (3) its failure to coordinate its restoration efforts with local public safety officials. The Department will not revisit our findings in D.P.U. 09-01-A regarding the Company's performance. Instead, similar to our treatment of the Company's vegetation management practices, our investigation focuses on the extent to which the Company's failure to properly plan and prepare for storm events resulted in the Company's incurring higher costs to repair damage and restore service to its ratepayers during the Storm.

The Attorney General identifies several ways in which Company's poor planning and preparation contributed to increased Storm costs. First, the Attorney General asserts that the Company's failure to establish agreements with contractors for responding to storm outages at negotiated rates resulted in it paying crews at double-time rates because the Company had to take whatever crews were available (Attorney General Brief at 123). The record evidence in this proceeding does not support the Attorney General's assertions on this matter. The rates paid to contractor crews for storm duty are established by collective bargaining agreements that govern crew reimbursement; companies that use the crews have no ability to negotiate rate discounts (Exhs. DPU-1-3 (electric); DPU-1-10 (electric); DPU-1-11 & Att. 1, at 6; Att. 2, at D-2 & Att. 3, at 2-3 (electric)). In addition, standard practice calls for crews to work 16 hours on and eight hours off, with all hours of storm duty paid at either time-and-a-half or double-time rates (Exh. DPU-1-3, Att. 1 (electric)).[34] The Company obtained the majority of contractor crews through NEMAG, including a significant number of crews provided by National Grid (Exh. DPU-1-3, Att. 3 (electric)). The rates paid to those contractors are established by the NEMAG and EEl agreements that govern the use of such crews (Exh. DPU-1-3 (electric)). Thus, while the Company's poor planning and preparation increased the time needed to restore service to its customers, there is no evidence to indicate that the Company paid higher rates to contractors than (1) it would have paid had it been better prepared, and (2) other state electric distribution companies paid for contractor crews.

Second, the Attorney General asserts that the Company incurred higher travel costs because of its need to import crews to assist in the restoration process. While it is true that, all else being equal, using local crews instead of crews that need to be brought in from a distance will save in travel-related costs, the record is unclear whether, given the footprint and severity

[34] Although there were some instances in which contractors worked more than 16 hours in a day, those instances appear to be limited to specific circumstances and did not result in the Company paying higher rates for those contractors (Exh. Unitil-TPM/KES/RLF-Rebuttal-1, at 27-28; DPU-1-2, Att. 2, at 215-216; 229, 232, 235, 239, 259, 262, 269 (electric); DPU-1-2, Att. 11, at 10, 36, 38, 86,104, 116 (electric); Tr. 9, at 1154).

of the Storm damage across major portions of the Northeast United States, the Company could have avoided the use of distantly located crews.[35]

Finally, the Attorney General asserts that the Company's lengthy repair effort increased costs because fallen trees placed additional stress on the Company's lines (Attorney General Brief at 123, citing Exh. AG-HWS- 1, at 16 (electric)). The Department sees little merit in the Attorney General's assertion on this matter. While better preparation might have allowed the Company to restore service in less time, the Attorney General has provided no record evidence that allows us to ascertain (1) whether timely restoration would have reduced stress (and damage) on the Company's overhead lines and, if so, (2) the amount of damage attributable to increased stress on the lines.

The Department concludes that the evidence in this proceeding fails to demonstrate that the Company's poor storm planning and preparation resulted in its incurring significantly higher Storm costs. Based on the above, we allow the Company to recover the remainder of its deferred Storm costs, $11,404,288.

f. Ratemaking Treatment of Recoverable Winter Storm 2008 Costs

The Company proposes to recover Storm costs on a reconciling basis[36] over seven years, with carrying charges based at its WACC (RR-DPU-67, Att. 1, at 104

[35] In addition, the sharing of travel costs with National Grid for crews brought in by that company served to mitigate any additional costs that the Company may have incurred (Tr. 9, at 1166-1169).

[36] The Company's proposed storm recovery adjustment factor ("SRAF") would allow the Company to petition to change the SRAF should significant over- or under-recoveries occur or expect to occur. (RR-DPU-67, Att. 1, at 104 (proposed M.D.P.U. No. 205, Sheet 1)). Further, it would allow the Company to reconcile revenue billed through the SRAF and the amount subject to recovery (RR-DPU-67, Att. 1, at 104 (proposed M.D.P.U. No. 205, Sheet 1)).

(proposed M.D.P.U. No. 205, Sheet 1)). Under its proposal, the Company would recover these costs through a storm recovery adjustment factor of $0.00498 per kWh, which it projects would recover $2,193,587 annually, or $15,355,109 over the seven-year period (Exh. Sch. RevReq - 14 (Supp. 3) at 1). Based on the disallowances discussed above, the Company is allowed to include $11,404,288 of Storm costs in rates.

We start by addressing the Company's proposal to implement a reconciling mechanism to recover allowable Storm costs.[37] In two recent decisions, the Department allowed companies to recover costs associated with Winter Storm 2008 on a reconciling basis, amortized over a five-year period with carrying charges. See Western Massachusetts Electric Company, D.P.U. 10-70, at 195-201 (2011); Massachusetts Electric Company/Nantucket Electric Company d/b/a National Grid, D.P.U. 09-39, at 209-213 (2009). In both of these decisions, the Department allowed the reconciling factor because, in part, the companies had not yet presented final Storm-related costs for review. D.P.U. 10-70, at 197-198; D.P.U. 09-39, at 211-212.[38] Because the instant proceeding completes the Department's

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37 The Company also proposes to create a storm fund to cover the costs of major storms going forward. This proposal is discussed below in Section X.P.

38 Through rate settlements, both National Grid and WMECo have storm funds that permit them to recover storm restoration costs. D.P.U. 10-70, at 186-187, citing Western Massachusetts Electric Company, D.T.E. 06-55 (2006); D.P.U. 09-39, at 205, citing Massachusetts Electric Company/New England Power Company/Eastern Edison Company, D.T.E. 99-47 (2000). Because National Grid and WMECo's storm funds were insufficient to cover expenses incurred in Winter Storm 2008, however, both sought approval to recover remaining Storm costs in recent rate cases. D.P.U. 10-70, at 187-188; D.P.U. 09-39, at 209-210. In D.P.U. 09-39, at 211-212, the Department approved National Grid's proposal to apply carrying charges to the remaining recoverable Storm costs based at its WACC. In D.P.U. 10-70, at 199-200, the Department rejected Western Massachusetts Electric Company's proposal to calculate carrying charges based at its WACC, and instead directed the company to calculate carrying charges based on its customer deposit rate.

review of the Company's Storm costs, the issue of final Storm costs being available is not a consideration. Rather, based upon the Company's poor vegetation management before the Storm, its mismanagement of its Storm response, and traditional ratemaking principles, specifically our goal of balancing the risk between ratepayers and shareholders with regard to recovery of costs, the Department rejects the Company's proposal to recover its allowable Storm costs on a reconciling basis.[39] Therefore, we determine that the Company should recover its allowable Storm costs within base rates.

The Department also finds it necessary to re-examine not only the ratemaking treatment, but the amortization period and the application of carrying charges for Storm-related costs. First, with respect to the amortization period, although the Department often allows companies to collect storm-related costs over a three- to five-year amortization period, we also may extend the amortization period based upon the facts of the particular proceeding. D.P.U. 09-39, at 211, citing Aquarion Water Company, D.P.U. 08-27, at 100 (2009)

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[39] Moreover, the Department considers specific criteria when determining whether to allow a new fully reconciling mechanism, including the volatility of the cost and whether it is beyond the company's control. See, e.g., D.P.U. 10-70, at 48.

(approving a seven-year amortization period for deferred expenses); Boston Edison Company, D.P.U. 19991, at 28 (1979) (approving a five-year amortization period for Storm costs); D.P.U. 906, at 241 (approving a 13-year amortization period in view of the magnitude of Pilgrim II expenses). Amortizations are based on a case-by-case review of the evidence and underlying facts. D.P.U. 08-27, at 99, citing Barnstable Water Company, D.P.U. 93-223-B at 14 (1994); D.P.U. 84-145-A at 54. In determining the proper amortization period, the Department must balance the interests of a company and its ratepayers, taking into account such factors as the amount under consideration for deferral, the value of such amount to ratepayers based on certain amortization periods, and the impact of the adjustment on the company's finances and income. D.P.U. 10-70, at 199, citing D.P.U. 08-27, at 99; D.P.U 93-223-B at 14. Taking all factors into consideration, including the burden to ratepayers if amortized over a lesser period, the Company's poor performance in vegetation management practices before the Storm, its poor storm planning and preparation, and the adverse effect the Company's Storm performance had on its customers, the Department finds that a seven-year amortization period is appropriate.

Second, turning to the question of carrying costs, in D.P.U. 09-39, at 210-211, the Department approved National Grid's proposal to calculate its carrying costs based at its WACC, in part because of the company's "excellent preparedness" in responding to the Storm. In D.P.U. 10-70, at 199-201, the Department rejected WMECo's proposal to calculate carrying charges based at its WACC. Instead, the Department directed the company to calculate carrying charges based on its customer deposit rate, stating that such an approach more equitably balances the risk of storm cost recovery between ratepayers and shareholders. D.P.U. 10-70, at 201. Although the particular facts in both D.P.U. 09-39 and D.P.U. 10-70 warranted approving a reconciling mechanism with carrying costs for recovery of National Grid and WMECo's Storm costs, in the instant case we have further considered the balancing of risk between the ratepayers and shareholders and determined that base rate treatment is more appropriate for Fitchburg's Storm costs. We have said that amortization of extraordinary expenses over a reasonable time represents an appropriate and reasonable sharing of the risk of large, unanticipated expenditures between ratepayers and shareholders. Massachusetts Electric Company, D.P.U. 92-78, at 9 (1992), citing Boston Edison Company, D.P.U. 1720, at 89 (1984). In addition, based on our longstanding precedent, we do not allow a return on the unamortized balance of extraordinary expenses. Cambridge Electric Company, D.P.U. 92-250, at 136 (1993); D.P.U. 88-135/151, at 28; D.P.U. 85-270, at 131-132; D.P.U. 1720, at 89. The rationale for not permitting such a return is to balance the burden of the extraordinary loss between ratepayers and shareholders. D.P.U. 88-135/151, at 28; D.P.U. 85-270, at 131-132; D.P.U. 1720, at 89. Taking all factors into consideration, as discussed above, the Department finds it appropriate and reasonable to deny the Company's request to apply carrying charges to the ratemaking recovery of the Company's Storm costs.

Based on the above, the Department allows the Company to include $11,404,288 in Storm costs in base rates, amortized over seven years with no carrying charges. Accordingly, this results in an annual allowable Storm cost recovery of $1,629,184. Compared to the Company's cost recovery proposal, such ratemaking treatment will result in a decrease of approximately $3.8 million in carrying costs that the Company proposed to recover from its ratepayers over the seven-year amortization period (see Exh. Sch. RevReq-14 (Supp. 3) at 1).

VI. REVENUE DECOUPLING MECHANISM PROPOSALS

A. Background on Revenue Decoupling

1. Introduction

In Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 32, 81-82 (2008), the Department directed each electric and gas distribution company to propose a full revenue decoupling mechanism in its next base rate proceeding. The Department stated that the objective of decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objectives of: (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources; and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources." D.P.U. 07-50-A at 31-32.

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

2. Prior Revenue Decoupling Proceedings

a. D.P.U. 09-30

In Bay State Gas Company, D.P.U. 09-30, at 89 (2009), the Department approved a revenue decoupling mechanism for Bay State Gas Company ("Bay State") that established the company's target revenue in that rate case by using the framework of revenue-per-customer. The Department reaffirmed the same ratemaking standard outlined in D.P.U. 07-50-A at 48-50, and approved the proposed mechanism, which allowed target revenue to increase as a result of growth in the number of customers but not as a result of growth in usage per customer. D.P.U. 09-30, at 93-95. The Department also approved a targeted infrastructure recovery factor ("TIRF") for Bay State, which allows an adjustment to target revenue to provide for the annual recovery of incremental costs of a program to replace gas distribution lines that are made of non-cathodically protected steel. D.P.U. 09-30, at 119, 134. The Department denied Bay State's request to retain a portion of its pre-existing performance based regulation ("PBR") rate plan in order to adjust its target revenue for the effects of inflation. D.P.U. 09-30, at 22-23, 25.

b. D.P.U. 09-39

In D.P.U. 09-39, at 61-64, 74, the Department approved a full revenue decoupling mechanism for National Grid's electric operations that reconciles a target level of revenue established in the rate case and actual revenue on an annual basis using a uniform kWh surcharge fee or credit. As such, National Grid's actual revenue is reconciled with its target revenue requirement, independent of any changes in the number of customers or average customer usage. See D.P.U. 09-39, at 9, 74. In D.P.U. 09-39, at 81-84, the Department also approved a CapEx mechanism for National Grid. Unlike Bay State's TIRF, which is a targeted capital investment program, National Grid's CapEx is a general capital investment program that is limited to an amount of expenditures equal to National Grid's three-year historical average of electric capital expenditures. D.P.U. 09-39, at 82. The Department did not approve National Grid's proposed annual inflation adjustment to its target revenue because National Grid failed to: (1) account for recent and pending initiatives to improve productivity, such as its acquisition of the KeySpan gas distribution companies; and (2) perform its own elasticity and productivity offset assessment and instead, relied on those performed by other utilities. D.P.U. 09-39, at 74, 76-78.

c. D.P.U. 10-55

In D.P.U. 10-55, at 40, 54, the Department approved a revenue decoupling mechanism for National Grid's gas operations that established its target revenue in that rate case by using a revenue-per-customer approach. The Department also approved a proposed TIRF, which allows an adjustment to target revenue to provide for the annual recovery of incremental costs of a program to address a high natural gas leak rate. D.P.U. 10-55, at 67-68, 129. The Department did not approve a proposed inflation adjustment on the basis that it: (1) was not necessary in the absence of a PBR plan;[40] and (2) would result in an unreasonably long time period between base rate proceedings. D.P.U. 10-55, at 64-66.

d. D.P.U. 10-70

In D.P.U. 10-70, at 43 (2011), the Department approved a full revenue decoupling mechanism for WMECo that reconciles target revenue and actual revenue on an annual basis through a uniform kWh charge or credit. WMECo's actual revenue is reconciled with its target revenue requirement independent of any change in the number of customers or average customer usage. See D.P.U. 10-70, at 10. In D.P.U. 10-70, at 49-52, the Department rejected WMECo's proposed reliability-related capital cost adjustment mechanism ("CCAM") because the company was unable to demonstrate that: (1) the proposed investments would improve reliability in a cost-effective manner; (2) decoupling would limit WMECo's ability to make necessary capital investments absent a capital recovery mechanism; and (3) the mechanism was in the best interests of the company's ratepayers. The Department also

[40] In approving PBR plans, the Department previously sought to, among other things, establish rates for a minimum period of five years and allowed electric and gas distribution companies inflationary adjustments to all rates and, therefore, all of the companies' underlying costs. See e.g., Incentive Regulation, D.P.U. 94-158, at 45-46, 51-52 (1995); Electric Industry Restructuring, D.T.E. 96-100, at viii, 73-74 (1996). In general, PBR-related inflation adjustments: (1) provided distribution companies with relief from inflationary increases to costs while retaining the incentive to control costs by optimizing operational efficiency; and (2) included ratepayer benefits such as fixed terms and earnings sharing mechanisms. D.P.U. 10-55, at 65; D.P.U. 07-50-A at 49.

declined to approve WMECo's proposed annual inflation adjustment to its target revenue because the Department found that an inflation adjustment mechanism: (1) was not necessary during a period of historically low inflation; (2) was not in the best interest of ratepayers; and (3) would likely result in an unreasonably long time period between base rate proceedings. D.P.U. 10-70, at 53-55.

B. Company's Electric Revenue Decoupling Proposal

1. Introduction

Fitchburg proposes a revenue decoupling mechanism for its electric division that would annually reconcile actual billed distribution revenue and a target level of revenue through a kWh charge, based on projected sales, to be recovered over the subsequent twelve-month period (Exh. Unitil-JDS-1, at 15-16 (electric)). Along with its revenue decoupling mechanism, Fitchburg also proposes a CCAM which would allow the Company to recover the costs associated with post-test year capital additions (Exh. Unitil-JDS-1, at 16-17, 19 (electric)).

2. Annual Target Revenue and Adjustments

a. Introduction

Fitchburg proposes to submit filings in support of its calculation of adjustments to the target level of revenue on or about November 1st of each year, with these adjustments to take effect on January 1st of the following calendar year (Exhs. Unitil-JDS- 1, at 17-18 (electric); Sch. JDS-4, at 2 (electric)). Fitchburg proposes two adjustment factors: (1) a factor to reconcile the difference between actual billed distribution revenue and proposed target revenue for the current year, in addition to the difference between actual revenue and target revenue for the prior year ("RDM adjustment"); and (2) a factor to recover the incremental revenue requirement associated with post-test year capital additions pursuant to its proposed CCAM adjustment (Exhs. Unitil-JDS- 1, at 15-19 (electric); Sch. JDS-4, at 2 (electric)).

Fitchburg proposes two caps on its proposed adjustment factors: (1) a cap on the annual RDM adjustment equal to one percent of the Company's total revenues;[41] and (2) a cap on the annual CCAM adjustment equal to three percent of total revenues (Exh. Unitil-JDS- 1, at 18, 23 (electric); RR-DPU-67, Att. 1, at 100 (proposed M.D.P.U. No. 203, Sheet 7)). Any unrecovered revenues in excess of these caps would be deferred for recovery in the next adjustment period with carrying charges at the monthly prime rate in accordance with 220 C.M.R. § 6.08(2) (Exh. Unitil-JDS-1, at 18, 23 (electric); RR-DPU-67, Att. 1, at 100 (proposed M.D.P.U. No. 203, Sheet 7)).

b. RDM Adjustment

Fitchburg proposes to calculate its RDM adjustment by determining the difference between its actual billed revenues[42] and target revenues[43] for each customer class over a

[41] Total revenues include revenues for distribution service, transmissions service, transition charges, energy efficiency, basic service, and all other related revenues (Exh. Unitil-JDS-1, at 23 (electric)).

[42] Fitchburg states that actual revenues will include revenues from special contract customers, which will be determined in accordance with the terms of the special contracts (Exh. Unitil-JDS-1, at 17 n. 19 (electric)).

[43] Fitchburg proposes to determine its initial target revenue in this proceeding and then adjust it annually to recover the costs of its proposed CCAM, as discussed below (Exh. Unitil-JDS-1, at 16, n. 18 (electric)).

twelve-month period from January through December of each year (Exh. Unitil-JDS-1, at 16 (electric)).[44] Then, the Company will divide the sum of these differences by its projected sales over the subsequent recovery period (January through December of the following year) to obtain a cents-per-kWh charge or credit (Exh. Unitil-JDS- 1, at 16 (electric)). The RDM adjustment also would include a final reconciliation of actual and allowed revenues for the prior calendar year (Exh. Unitil-JDS- 1, at 18 (electric)). The resulting charge or credit associated with the RDM adjustment would take effect on January 1st of the following year (Exh. Unitil-JDS- 1, at 17 (electric)). The Company proposes to request a mid-period adjustment if the RDM under- or over-collection is projected to exceed ten percent by the end of the year (Exh. Unitil-JDS- 1, at 18 (electric)).

c. Capital Cost Adjustment Mechanism

Fitchburg proposes an annual adjustment to the Company's target revenue to recover its incremental capital investments (Exh. Unitil-JDS-1, at 15-17 (electric)). The proposed CCAM would annually adjust rates to collect the revenue requirement associated with an allowed level of capital spending (Exh. Unitil-JDS- 1, at 19-20 (electric)). The allowed level of capital spending is defined as booked plant additions for a particular year, net of plant retirements and salvage value (and such values could be positive or negative), which may not exceed the capital

44 Because Fitchburg will make its RDM filing in November, it will have actual data only for January through September. Therefore, its RDM adjustment calculations will be based on nine months of actual data and three months of projected data (Exh. Unitil-JDS-1, at 17-18 (electric)). Projected data will be replaced with actual data in the subsequent reconciliation filing and adjustment (Exh. Unitil-JDS-1, at 18 (electric)).

spending limit minus the annual allowance for depreciation expense (Exh. Unitil-JDS-1, at 20 (electric); RR-DPU-67, Att. 1, at 95 (proposed M.D.P.U. No. 203, Sheet 2)). The Company proposes an annual spending limit of $7,305,233, which is the average of its capital spending between 2007 and 2009 (Exhs. Unitil-JDS-1, at 20 (electric); Sch. JDS-6 (rev.) (electric)). The Company's estimated average capital budget from 2011 to 2015 is $7,374,809 per year (Exh. Sch. TPM-1 (electric)).

The CCAM revenue requirement would be calculated to include the annual depreciation on cumulative incremental rate base[45] resulting from allowed capital spending, plus the pre-tax return, as established in this base rate proceeding, on year-end cumulative rate base (Exh. Unitil-JDS- 1, at 21 (electric)). Fitchburg proposes to determine the annual incremental CCAM revenue requirement for each rate class by multiplying the cumulative CCAM revenue requirement by a CCAM net plant allocator (Exh. Unitil-JDS-1, at 22 (electric)). To calculate the CCAM rate adjustment for the residential rate class, the Company would divide its revenue requirement for that rate class by the forecasted kWh sales (Exh. Unitil-JDS-1, at 22 (electric)). As C&I rate classes have demand charges, the Company would calculate the CCAM rate adjustments for these classes by: (1) dividing the ratable portion[46] of the rate

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[45] Cumulative incremental rate base is the product of cumulative allowed capital spending adjusted by cumulative depreciation and deferred tax reversals (Exh. Unitil-JDS-1, at 21 (electric)).

[46] The kW demand charge ratable portion of the CCAM revenue requirement is the proportion of the rate class' total revenues that are derived from kW demand charges, multiplied by the CCAM revenue requirement for that rate class (Exhs. Unitil-JDS-1, at 22-23 (electric); Sch. JDS-9 (electric)).

class-specific CCAM revenue requirement kW revenues by the rate class' projected kW demand billing determinants; and (2) dividing the remaining revenue requirement for a given rate class by its projected kWh billing determinants (Exhs. Unitil-JDS-1, at 22-23 (electric); Sch. JDS-9, at 1-2 (electric)).

In support of its future proposed CCAM and RDM adjustments, the Company would submit: (1) detailed documentation of all plant additions and retirements that were booked in the previous calendar year[47] by July 1st of each year; and (2) additional documentation and detailed support of the CCAM and RDM rate calculations at least 60 days prior to the January 1st effective date (Exh. Unitil-JDS- 1, at 21-22 (electric)).

C. Company's Gas Revenue Decoupling Proposal

1. Introduction

For its gas division, Fitchburg proposes an RDM adjustment that consists of semi-annual rate adjustments to the Company's seasonal peak and off-peak[48] rates to reconcile the difference between actual revenue-per-customer and revenue-per-customer targets for designated customer groups, as established in this proceeding (Exh. Unitil-JDS-1, at 15-16 (gas)). Unlike its electric RDM adjustment and its CCAM, Fitchburg's proposed gas

[47] The Company would file its initial CCAM on July 1, 2012 and it would include supporting data for investments made in calendar years 2010 and 2011. Subsequent filings would include only investments made in the previous calendar year (Exh. Unitil-JDS- 1, at 21 (electric)).

[48] Fitchburg's peak period runs from November 1st through April 30th and its off-peak period runs from May 1st through October 31st (RR-DPU-67, Att. 3, at 149-150 (proposed M.D.P.U. No. 159, Sheets 2-3)).

RDM adjustment and its TIRF mechanism will operate independently from one another, which means that its revenue-per-customer targets for the gas division will not be affected by its TIRF adjustments (Exh. Unitil-JDS- 1, at 16 (gas)). Fitchburg's proposed TIRF is addressed in Section VII, below.

2. Benchmark or Target Revenue-Per-Customer

Fitchburg proposes to establish its benchmark or target revenue-per-customer based on the revenues and customer counts associated with three groups of customers: (1) the residential non-heating group, which includes the R-1 and R-2 rate classes; (2) the residential heating group, which includes the R-3 and R-4 rate classes, and; (3) the C&I group, which includes the G-41, G-42, G-43, G-51, G-52, and G-53 rate classes (Exh. Unitil-JDS-1, at 16 (gas)).

3. Revenue Decoupling Mechanism Adjustments

Fitchburg proposes to file its peak period RDM adjustment together with its annual local distribution adjustment factor ("LDAF") on or about August 1st of each year, and file its off-peak period RDM adjustment on or about February 1st of each year (Exh. Unitil-JDS-1, at 19 (gas)). The annual peak and off-peak RDM adjustments would be calculated on the basis of the most recently completed peak or off-peak period (Exh. Unitil-JDS- 1, at 19 (gas)). The filings would also include a final reconciliation of actual and allowed RDM revenues for the prior peak- or off-peak periods (Exh. Unitil-JDS-1, at 19 (gas)).

The Company proposes to calculate the seasonal RDM adjustments based on a three-step process. First, Fitchburg would calculate the difference between: (1) the target revenue-per-customer for each season and customer group, which will be determined in this proceeding; and (2) the actual revenue-per-customer for that group,[49] as determined by actual booked base distribution revenues and the group customer count from the most recently completed same season (Exh. Unitil-JDS- 1, at 18-19 (gas)). Second, the Company will calculate its total revenue shortfall or surplus by summing the products of: (1) the resulting revenue-per-customer differentials; and (2) the actual number of existing customers in each corresponding group (Exh. Unitil-JDS- 1, at 18 (gas)). Last, the Company will calculate a uniform RDM adjustment (for all customers) to take effect in the upcoming season by dividing the total revenue shortfall or surplus, by the total projected therm deliveries for next season (Exh. Unitil-JDS- 1, at 18 (gas)). This adjustment would also include a final reconciliation of the revenue decoupling adjustment authorized during the prior season (Exh. Unitil-JDS-1, at 18 (gas)). The resulting dollar per therm adjustment would be included in the Local Distribution Adjustment Charge ("LDAC") and applied to customer bills in the next corresponding season (RR-DPU-67, Att. 3, at 150 (proposed M.D.P.U. No. 159, Sheet 3)).

Fitchburg proposes annual caps on the peak and off-peak period RDM adjustments equal to three percent of total revenues from firm sales and firm transportation throughput, based on the most recent corresponding peak or off-peak period (Exh. Unitil-JDS-1, at 20 (gas)). Total revenues would include revenue from distribution service, the cost of gas

[49] The Company further proposes that actual revenue exclude revenue from new customers, as discussed below in the context of the Company's proposed treatment of new customers.

adjustment factor ("CGAF"), the LDAFs, and all other related charges and transportation revenues would be adjusted by imputing the Company's cost of gas charges for that period (RR-DPU-67, Att. 3, at 150-151 (proposed M.D.P.U. No. 159, Sheets 3-4)). Any unrecovered revenues in excess of these caps would be deferred until the next year with carrying charges at the monthly prime rate in accordance with 220 C.M.R. § 6.08(2) and included in the next corresponding peak or off-peak period adjustment (Exh. Unitil-JDS-1, at 20 (gas)).

4. Treatment of New Customers

Fitchburg proposes to separately track and retain the revenues associated with customers who are added after the end of the 2009 test year, thereby entirely excluding them from annual RDM calculations until the Company's next rate case (Exh. Unitil-JDS-1, at 17, 19 (gas)). The Company defines a new customer to be a premise or location that requires the installation of a new service, meter and/or the extension or reinforcement of the distribution system in order to serve that location (Exh. Unitil-JDS-1, at 17 (gas)).

5. Treatment of Residential Non-Heating to Heating Conversions

Fitchburg proposes that it be permitted to retain the incremental revenues associated with residential non-heating service to heating service customer conversions (Exh. Unitil-JDS- 1, at 17 (gas)). Under the Company's proposal, a residential customer that converts from non-heating to heating service would decrease the residential non-heating customer count by one and increase the residential heating customer count by one, starting in the month in which the conversion takes place (Exh. DPU-7-14 (gas)). As a result, the

Company would retain as incremental revenues the difference between a specified revenue-per-customer amount for the residential non-heating and residential heating groups (Exh. DPU-7-14 (gas)).

6. Special Contract Revenues

During the test year, Fitchburg had one gas and two electric customers that were served under individually-negotiated special contracts (Exhs. AG-1-99 (electric); AG-1-99 (gas)).[50] To calculate the revenue targets for all rate classes in this proceeding (i.e., in both the electric and gas divisions), the Company deducted the special contract revenue from the test year's total revenue requirement and it excluded special contract loads from the class load data for large C&I customers (Exh. Unitil-PMN-1E at 12-13). However, Fitchburg proposes to include the revenues associated with its electric special contract customers as part of its electric target revenue (Exh. Unitil-JDS- 1, at 17 n. 19 (electric)). Conversely, Fitchburg proposes to exclude from the calculation of the revenue decoupling adjustment factor for the gas RDM, revenues from new, post-test year special contract customers (Exh. AG-20-3 (gas); Tr. 14, at 1782-1784).

In separate proceedings, the Department approved two new special contracts, one electric and one gas, with one of the Company's existing large industrial customers. See Fitchburg Gas and Electric Light Company, D.P.U. 11-EC- 1, Stamp-Approval

[50] Pursuant to G.L. c. 164, § 94A, the Department may approve a gas or electric distribution company's request to enter into a special contract by which the company agrees to offer service to a customer at a rate or under terms that vary from the standard tariffed rate.

(July *25*, 2011); Fitchburg Gas and Electric Light Company, D.P.U. 11-GC-3, Stamp-Approval (July *25*, 2011). The Company proposes to include the electric special contract revenues as actual revenues for calculating any electric RDM adjustment (Exh. AG-30-2 (electric); RR-DPU-67, Att. 1, at 96 (proposed M.D.P.U. No. 203, Sheet 3)). The Company proposes to treat the gas special contract revenues as if they were from a "new" customer, which would exclude them from the calculation of the RDM adjustments for the gas division (i.e., allowing all special contract revenue (both existing and new) to be retained by the Company) (Exh. AG-20-3 (gas)).

D. Positions of the Parties

1. Attorney General

a. Revenue Decoupling for Electric and Gas Divisions

The Attorney General argues that the Company's revenue decoupling proposals lack sufficient reporting requirements and recommends that the Department impose the same reporting requirements it required of WMECo in D.P.U. 10-70 (Attorney General Brief at 41). Specifically, the Attorney General contends that the Company should be required to provide the following data for residential, commercial, industrial, and street lighting customers: (1) monthly customer counts; (2) monthly kWh or therm sales; (3) weather-normalized monthly kWh or therm sales; (4) lost base revenue from energy efficiency programs for the most recent calendar year available; and (5) forecasted sales for the next two years (Attorney General Brief at 41).

b. <u>Target Revenue for Electric Division</u>

The Attorney General argues that, when determining the Company's revenue deficiency in this case, the Department should increase the Company's test year revenue for the electric division by $1,022,692 (or 6.1 percent): (1) to account for known and measurable post-test year sales growth; and (2) to ensure that representative levels of costs and revenues are established for the Company in this proceeding (Attorney General Reply Brief at 50, 52). The Attorney General contends that the net loss reported by Fitchburg's electric division for the 2009 test year was a result of the recent economic recession, which has subsided and, therefore, the 2009 test year does accurately represent the Company's true revenues (Attorney General Reply Brief at 51, <u>citing</u> Exh. AG- 1-2, Att. 3G at 4 (electric)). She adds that the Company's electric sales volume (in kWh) has increased by 6.1 percent in 2010 and that its net income has improved by almost $4 million since the 2009 test year (Attorney General Reply Brief at 51, <u>citing</u> Exh. AG- 1-2, Att. 3G at 4 (electric); Company Brief at 112; Tr. 8, at 893).

c. <u>Capital Cost Adjustment Mechanism</u>

The Attorney General contends that the Department should reject the Company's proposed CCAM for a number of reasons (Attorney General Brief at 28-29; Attorney General Reply Brief at *45).* First, the Attorney General argues that, if approved, the proposed CCAM would shift investment risk from the Company to its customers by eliminating regulatory lag, a traditional ratemaking mechanism that encourages companies to make disciplined investment decisions (Attorney General Brief at 20-21). Further, the Attorney General argues that the

CCAM would shift the burden of proof for establishing the prudence of capital investments from the Company to the Department and other intervenors. She also argues that the CCAM annual review process, as proposed, would not provide the Department and other parties with adequate time to properly review the prudence of capital additions (Attorney General Brief at 20-21).

The Attorney General also contends that Fitchburg has not demonstrated that a departure from normal rate base treatment is warranted. According to the Attorney General, Fitchburg has failed to show that: (1) prices for its underlying costs are volatile; (2) capital spending requirements are beyond its control; or (3) service quality is deteriorating (Attorney General Brief at 26-28).[51] Further, the Attorney General argues that the Company's reliability performance, as measured by its system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") metrics, is comparable to the performance of its peers and, historically, that the Company has managed to obtain the capital it needed to replace infrastructure and make reliability improvements without a CCAM (Attorney General Brief at 17-18, citing Exh. AG-DED- 1, at 11-13, 21-22 (electric))[52]

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51 The Attorney General argues that the Supreme Judicial Court has approved rate adjustments under formula tariffs for the recovery of actual costs in circumstances in which the utility has no bargaining power and where costs are: (1) volatile; (2) objectively ascertainable; and (3) material (Attorney General Brief at 26, citing Consumers Organization For Fair Energy Equity, Inc. v. D.P.U., 368 Mass. 599, 601 608, 606 n. 9 (1975) ("COFFEE") (energy supply costs)). Further, she claims that the Department recently outlined the criteria it considers when evaluating such mechanism as: "(1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control." (Attorney General Brief at 26, citing D.P.U. 10-70, at 48).

52 The Attorney General states that the Company's capital spending per customer has increased approximately three-fold over the past ten years, period during which the Company has filed only two rate cases and has not benefited from a CCAM (Attorney General Brief at 18, citing Exh. AG-DED-1, Sch. DED-6 (electric)).

In response to the Company's claim that it has relied on post-test year sales increases as a source of financing for infrastructure investments, the Attorney General argues that this logic is counterintuitive because robust growth and economic activity would likely result in fewer rate cases, not more, all else being equal (Attorney General Reply Brief at 46-47, citing Company Brief at 111). Further, she asserts that the Company's argument is misplaced because it implies that its test year revenues are not representative and may need adjustments, and not that its test year-based revenue requirement is insufficient to finance capital investments (Attorney General Reply Brief at 47).

The Attorney General asserts that it is unfair to burden ratepayers with the expense of CCAM investments without any quantification or representation of their benefits (Attorney General Brief at 20). She notes that the Company has not performed cost-benefit or cost-effectiveness analyses in support of its proposed CCAM budget and that it has also failed to propose any metrics, reliability-related goals, reductions in O&M costs, or other benchmarks by which to measure the success or failure of the CCAM (Attorney General Brief at 19-20, 22-23, citing Exh. AG-9-35 (electric); Attorney General Reply Brief at 46).

According to the Attorney General, Fitchburg's proposed CCAM is much broader in scope than other capital trackers approved by the Department (e.g., the CapEx mechanism approved for National Grid's electric operations in D.P.U. 09-39) (Attorney General Brief at 19). In particular, the Attorney General notes that the CapEx mechanism was designed to recover capital expenditures related to National Grid's electric distribution system only, whereas Fitchburg's proposed CCAM would cover all capital expenditures for its electric division (Attorney General Brief at 24). Also, the Attorney General argues that the CapEx mechanism in D.P.U. 09-39 was supported by testimony that National Grid's electric distribution system was old and in need of replacement, whereas Fitchburg states only that the CCAM is needed to complement its proposed revenue decoupling mechanism (Attorney General Brief at 19, citing Exhs. Unitil-JDS-1, at 19 (electric); Unitil-TPM-1, at 27 (electric)).[53] Further, the Attorney General claims that the spending limit established in D.P.U. 09-39 was based on a relatively stable trend of historic capital spending, while Fitchburg's proposed capital spending limit for the CCAM is a three-year average that includes abnormally high costs associated with Winter Storm 2008 and are, therefore, not representative of Fitchburg's current investment needs (Attorney General Brief at 24-25, citing D.P.U. 09-39, at 82; Exhs. AG-DED-1 (electric); Sch. JDS-6 (electric); Unitil-MJ-3 (electric); Tr. 1, at 74-76).

[53] The Attorney General also argues that one of the implicit goals of the Department's decoupling mechanism is to reduce customer bills and that the increase to distribution rates resulting from the CCAM is contrary to this goal (Attorney General Brief at 28).

In addition, the Attorney General argues that Fitchburg's proposed cap on CCAM investments, which is equal to three percent of total revenue for the prior year, is excessive. She argues that this cap is higher than any other cap approved by the Department, including the cap on National Grid Electric's capital investments, which is a combined cap for both the CapEx and the RDM equal to three percent of total revenue for the prior year (Attorney General Brief at 24). If the Department concludes that the CCAM is warranted, the Attorney General recommends that the Department reduce the spending cap on the CCAM to $6 million per year so that the cap is more representative of the Company's historical capital spending (Attorney General Brief at 25, citing Exh. AG-RSH- 1, at 17-18 (electric)).[54]

Finally, the Attorney General argues that Fitchburg's proposal to apply interest charges to any capital costs in excess of the cap is unprecedented and that its proposal to defer excess costs to subsequent CCAM filings resembles a request that was rejected in D.P.U. 09-39, D.P.U. 10-55, and New England Gas Company, D.P.U. 10-114 (2010) (Attorney General Brief at 25 citing Exhs. AG-DED- 1, Sch. DED-9 (electric)).

d. Special Contract Revenues

The Attorney General opposes the Company's proposed treatment of the special contract revenues from a large industrial gas and electric customer (i.e., the special contracts at issue in D.P.U. 11-EC-0l and D.P.U. 11-GC-03) (Attorney General Brief at 185-186).

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54 The Attorney General states that the $6 million is roughly halfway between the Company's proposed cap and its average historical capital spending between 2000 and 2007 (Exh. AG-RSH- 1, at 17-18 (electric)).

Specifically, she opposes the Company's proposal to include test year-level revenues from this customer in the target revenue calculations for the gas and electric RDMs and to exclude post-test year revenue from this customer from the gas division's revenue decoupling adjustment calculations once the special contracts go into effect (Attorney General Brief at 186-187; Attorney General Reply Brief at 49). According to the Attorney General, this customer is expected to install a gas-fired electric generator on its premises, which means that the Company will likely experience a large decrease in electric revenues and a large increase in gas revenues (Attorney General Reply Brief at 49; Attorney General Brief at 188, citing Exh. AG-26-4 (confidential) (electric); AG-26-6 (confidential) (electric); AG-18-6 (confidential) (gas); AG- 18-8 (confidential) (gas)). Therefore, she contends that if the Company's proposal is approved, the Company will: (1) collect the revenue shortfall associated with the customer's decrease in electric consumption from all electric customers through the electric RDM; and (2) pursuant to the gas RDM, retain the incremental gas revenues associated with the customer's estimated increase in its gas consumption without incurring any additional capital costs (Attorney General Brief at 188-189, citing Exhs. AG-26-8, Att. (confidential) (gas); AG-18-8 (gas); AG-18-9 (confidential) (gas); AG-18-10, Att. (confidential) (gas)). She argues that the decreased electric consumption and increased gas consumption both constitute post-test year changes that are known and measureable and that the increased gas consumption will be a significant change (Attorney General Brief at 189). Because the Department's standard for post-test year adjustment is that changes must be known and measureable as well as significant, the Department should require the Company to include the special contract gas revenues in its computation of average revenues per customer and flow the benefits of the revenue through to customers (Attorney General Brief at 189-190). The Attorney General argues that, if the Company's proposal is approved shareholders would receive a windfall, and that this would be unjust, unreasonable, and inequitable (Attorney General Brief at 188-189).

In response to the Company's assertion that the gas and the electric divisions must treat special contract revenue differently because the energy efficiency program charge is collected only through the electric tariffs, the Attorney General states that because both divisions serve the special contract customer at issue, the customer is eligible for utility-sponsored energy efficiency measures regardless of whether the special contract for gas includes energy efficiency charges (Attorney General Reply Brief at 50).

The Attorney General argues that this issue demonstrates how revenue decoupling complicates traditional ratemaking because rates must be adjusted regularly for the normal ebb and flow of customers and usage levels (Attorney General Brief at 189). The Attorney General notes that the Company's proposed target revenues for its electric and gas divisions already include revenues from the customer at issue because the customer received electric and gas services at standard tariffed rates during the test year. The Attorney General argues that, instead of adopting Fitchburg's proposal the Department should require the Company to include all revenues from gas special contracts that become effective after the test year in its calculation of actual revenue-per-customer and flow the benefits of such revenue back to its gas customers (Attorney General Brief at 185-186, 188-190).

2. <u>DOER</u>

a. <u>Revenue Decoupling of Electric Division</u>

DOER asserts that the Company's revenue decoupling proposal for its electric division should be approved, subject to the same reporting requirements imposed upon WMECo in D.P.U. 10-70 (DOER Brief at 4 (electric)). DOER contends that the Company's proposal successfully decouples its revenue from its sales, which removes any disincentive regarding the adoption of cost-effective energy efficiency and demand response programs (DOER Brief at 4 (electric)). In addition, DOER claims that Fitchburg's proposed revenue decoupling mechanism is consistent with the mechanisms approved for other electric distribution companies (DOER Brief at 4 (electric)).

b. <u>Capital Cost Adjustment Mechanism</u>

DOER opposes the Company's proposed CCAM because it would explicitly reduce the Company's overall business risk, which DOER argues is not the intent of the Department's revenue decoupling policy (DOER Brief at 4 (electric)). According to DOER, the Company has not claimed that it has any serious issues with respect to system reliability and safety or that it will have any unusual capital requirements in the future (DOER Brief at 5 (electric) <u>citing</u> Exh. Unitil-TPM-1, at 10-11, 13 (electric)).[55] Instead, DOER contends that the

[55] According to DOER, a capital tracker may be warranted in circumstances in which a company demonstrates that such mechanism is necessary to maintain safe and reliable service or that revenue decoupling would preclude it from making necessary investments (DOER Brief at 4 (electric)).

Company was able to sustain a high level of reliability and has averaged approximately *3.5* years between rate case filings, despite a prolonged period of stagnant and/or declining sales (DOER Brief at *5-6* (electric) citing Exhs. Unitil-TPM-1, at *5* (electric); Unitil-JDS- 1, at 14 (electric)).

c. Revenue Decoupling of Gas Division

DOER supports the Company's proposed revenue decoupling mechanism but recommends that the Department impose annual reporting requirements consistent with those adopted in D.P.U. 10-70 (DOER Brief at 4 (gas)). DOER asserts that the Company's proposed gas revenue decoupling mechanism fully decouples revenues from its sales, which is consistent with the Department's objective to remove barriers to the implementation of cost-effective energy efficiency and demand response programs (DOER Brief at 4 (gas)). DOER further argues that Fitchburg's proposed revenue decoupling mechanism is consistent with those approved by the Department in D.P.U. 09-30, D.P.U. 10-55, and D.P.U. 10-114 (DOER Brief at 4 (gas)).

3. Environment Northeast

a. Revenue Decoupling of Electric Division and Capital Cost Adjustment Mechanism

ENE endorses the Company's proposed revenue decoupling mechanism for its electric division (ENE Brief at 6-7 (electric)). ENE states that the Company's proposal: (1) properly aligns the Company's financial incentives with the policy of investing in all cost-effective energy efficiency and demand side resources; and (2) is consistent with the directives and precedent from D.P.U. 07-50, D.P.U. 09-39, and D.P.U. 10-70 (ENE Brief at 6-7 (electric)). However, ENE argues that the cap on annual RDM adjustments should be increased from one percent to three percent, as this would be: (1) consistent with the caps approved by the Department in D.P.U. 09-39, D.P.U. 09-30, D.P.U. 10-55, and D.P.U. 10-114; and (2) large enough to "avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates" (ENE Brief at 6 (electric) citing D.P.U. 10-114, at 26; D.P.U. 10-55, at 43; D.P.U. 09-39, at 87).

ENE takes no position on Fitchburg's proposed CCAM. However, ENE notes that the proposed revenue decoupling mechanism can be approved and operate without the CCAM (ENE Brief at 6 (electric)).

b. Revenue Decoupling of Gas Division

ENE supports Fitchburg's proposed revenue decoupling mechanism for its gas division as ENE argues that the mechanism: (1) is consistent with the Department's directives in D.P.U. 07-50; (2) is similar to proposals previously approved by the Department; and (3) aligns the Company's financial incentives with the policy of investing in all cost-effective energy efficiency and demand side resources (ENE Brief at 8 (gas)). ENE also asserts that the Company's proposed three percent cap on RDM adjustments is reasonable and should be allowed (ENE Brief at 8 (gas)). ENE contends that the Company's proposal to retain incremental revenue associated with new customers until its next rate case is also consistent with prior rulings by the Department (ENE Brief at 8 (gas) citing D.P.U. 10-114, at 27-29; D.P.U. 10-55, at 45; D.P.U. 09-30, at 98-101).

4. Fitchburg

a. Revenue Decoupling of Electric Division

Fitchburg asserts that its proposed revenue decoupling mechanism for its electric division will sever the link between revenue and sales and, therefore, should be approved (Company Brief at 101, 107). Fitchburg claims that its proposed revenue decoupling mechanism is (1) similar to those already approved by the Department in D.P.U. 09-39 and D.P.U. 10-70, and (2) closely aligned with its proposed CCAM (Company Brief at 103-105). If the Department rejects the proposed CCAM, leaving the Company with no mechanism to collect the capital costs associated with adding new customers, Fitchburg requests that its electric decoupling proposal be modified to exclude revenue from new customers added after the test year (Company Brief at 103 n.12).

b. Target Revenue for Electric Division

Fitchburg opposes the Attorney General's recommendation that the target revenue for its electric division be increased by $1,022,692 to account for increased sales post-test year. Fitchburg argues that such an adjustment would be a violation of the ratemaking principle that rates should be set based on representative costs and billing determinants (Company Reply Brief at 55, citing Attorney General Reply Brief at 50-52). According to the Company, the Attorney General's proposal would create a mismatch because it would compare costs at 2009 levels with billing determinants at 2010 levels (Company Reply Brief at 55).

Furthermore, the Company claims there are fundamental rate setting principles and processes such as the relationship between the Company's revenue requirement and its allocated cost study, that would be rendered obsolete if the arbitrary revenue adjustment proposed by the Attorney General is approved (Company Reply Brief at 56).

c. Capital Cost Adjustment Mechanism

Fitchburg argues that its proposed CCAM would provide it with the revenues necessary to make capital investments while at the same time preserving its opportunity to earn a fair rate of return (Company Brief at 108-110). The Company argues that revenue decoupling will remove its potential for growth in revenues between rate cases, which has historically been a source of financing for the Company's capital investments (Company Brief at 108-110; Company Reply Brief at 49-50).

The Company contends that the Department has recognized that capital investment reconciliation mechanisms are necessary to provide companies with investment capital that would be otherwise restricted under revenue decoupling (Company Brief at 50-51, citing D.P.U. 09-39, at 79-80; D.P.U. 07-50-A at 48, 50). The Company argues that the objections raised by the Attorney General and DOER to the CCAM incorrectly presume that the Company is not facing any reliability concerns or extraordinary capital requirements and has managed to make necessary investments in the past without the CCAM (Company Brief at 111, citing Attorney General Brief at 17-18; DOER Brief at 5 (electric)). The Company argues that, despite a long-term trend of flat or decreasing sales, it has supported incremental capital investment in the past through periodic increases in revenues after base rate proceedings

(Company Brief at 11, citing Exh. AG-19-1 (electric); Tr. 8, at 983-985).[56] The Company states that a similar, periodic increase in sales volumes occurred in this proceeding as kWh sales in 2010 increased by 6.1 percent over 2009 test year levels (Company Brief at 112, citing Tr. 8, at 983). Fitchburg argues that the CCAM is warranted because revenue decoupling will result in the forfeiture of this type of increased incremental revenues (Company Brief at 112).

Fitchburg argues that its proposed capital spending limit for the CCAM, which is based on the Company's average capital spending between 2007 and 2009, is representative of the Company's current capital investment needs and is, therefore, appropriate (Company Brief at 114, citing D.P.U. 09-39, at 82; Company Reply Brief at 52).

The Company disputes the Attorney General's claim that Fitchburg lacks adequate studies to establish the cost-effectiveness of its planned capital additions (Company Reply Brief at 52). Fitchburg argues that its planned capital spending is corroborated by past investments and is plainly representative of current investment needs, which means that such studies are not required (Company Reply Brief at 52). In addition, the Company claims that the Attorney General incorrectly concludes that a CCAM only is appropriate for new programs or

[56] Fitchburg also disputes the Attorney General's assertion that its capital spending on a per customer basis has increased over the past decade (Company Brief at 112). The Company states that its actual capital spending, on a per customer basis, has decreased by 5.2 percent over the decade examined (Company Brief at 112 citing Unitil-JDS-Rebuttal-1, at 2).

accelerated investments (Company Brief at 113). Finally, the Company confirms that its proposed CCAM would not be used to recover any transmission-related investments (Company Brief at 113).

d. Revenue Decoupling of Gas Division

Fitchburg argues that its proposed revenue decoupling mechanism for its gas division is consistent with other mechanisms that have been approved by the Department and, therefore, should be approved (Company Brief at 105, 107, citing Exh. Unitil-JDS-1, at 11-12 (gas)). The Company claims that its proposal to exclude revenue from new customers from the gas RDM adjustment calculation is: (1) necessary in order to preserve the Company's incentive to add new customers; and (2) consistent with the Department's findings in D.P.U. 09-30, D.P.U. 10-55, and D.P.U. 10-114 (Company Brief at 106 n.16).

e. Special Contract Revenues

Fitchburg claims that its treatment of special contract revenue in its gas and electric revenue decoupling mechanism proposals is consistent with the Department's decision in D.P.U. 07-50-A as well as the gas revenue decoupling mechanisms approved for Bay State, National Grid's gas operations, and New England Gas Company ("NEGC") (Company Brief at 127). The Company asserts that it is appropriate to include special contract revenues in the target revenue for its electric division because electric customers who enter into a special contract must still pay an energy efficiency charge, making them eligible to participate in the Company's energy efficiency programs (Company Brief at 126). In contrast, the Company contends that its special contracts for gas customers do not include an energy efficiency charge, making gas special contract customers ineligible to participate in the Company's energy efficiency programs (Company Brief at 126-127). Further, the Company argues that its proposal is consistent with the Department's general revenue decoupling policy because it severs the link between revenues and consumption by customers who have access to energy efficiency program funds (see, e.g., Company Brief at 126-127).

The Company notes that, while it does not oppose the inclusion of revenues from previously approved special contracts in its electric and gas RDM adjustments, it opposes the Attorney General's recommendation to include any revenues associated with special contracts that become effective after the test year (Company Brief at 128-129). The Company contends that if post-test year special contract revenues were included in its RDM adjustments, it would have no incentive to enter into such special contracts, which are complicated and time-consuming to develop and get approved (Company Brief at 129).

E. Analysis and Findings

1. Introduction

Relying upon our delegated authority under G.L. c. 164, § 94 to prescribe the rates and prices that utilities may charge, the Department has adopted revenue decoupled rates as the model for all future ratemaking proceedings. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-B at 26 (2008), citing Boston Edison Co. v. City of Boston, 390 Mass. 772, 779 (1984). In D.P.U. 07-50-A at 24, the Department determined that promoting the implementation of all cost-effective demand resources is a top priority. The Department stressed that, in order to realize the full potential of demand resources, 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 24-25. In considering the various ratemaking alternatives that would promote the implementation of all cost-effective demand resources, the Department concluded that a full revenue 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 a general statement of policy and that issues such as the equity and appropriateness of specific cost allocations and revenue recovery would be investigated and addressed based on the evidentiary record in the adjudication of a distribution company's individual proposal to employ rates that decouple its revenues from its sales. D.P.U. 07-50-B at 28-29. Accordingly, the Department will evaluate the appropriateness of each mechanism on a case-by-case basis, taking into consideration all aspects of the proposal and any relevant circumstances. D.P.U. 07-50-A at 50.[57]

[57] In determining the propriety of rates, prices and charges, the Supreme Judicial Court has stated that the Department must find that they are just and reasonable. See Attorney General v. Dep't of Telecomm. and Energy, 438 Mass. 256, 264 n.13 (2002); Attorney General v. Dep't of Pub. Utils., 392 Mass. 262, 265 (1984).

2. Revenue Decoupling of Electric Division

a. Revenue Decoupling Mechanism

For its electric division, Fitchburg has proposed to adopt a full revenue decoupling mechanism whereby, on an annual basis, the Company's actual billed revenues would be reconciled with a target revenue level established in this proceeding. Fitchburg's revenue decoupling proposal would hold the Company harmless from losses in sales, regardless of their cause.

The Department has approved revenue-per-customer revenue decoupling mechanisms for Bay State in D.P.U. 09-30, National Grid's gas operations in D.P.U. 10-55, and NEGC in D.P.U. 10-114. The Department approved a total revenue approach to implement revenue decoupling, similar to Fitchburg's proposal, for National Grid's electric operations in D.P.U. 09-39 and for WMECo in D.P.U. 10-70.

Fitchburg asserts that in recent years, it has been unable to earn a reasonable rate of return due to a combination of: (1) its existing rate design, which recovers approximately 88 percent of the Company's base revenues through variable rates; and (2) difficult economic conditions within its service territory (Exh. Unitil-JDS-1, at 14 (electric)). The Company states that since January 2006, electric demand has decreased at an average annual rate of 2.7 percent, as measured by rolling twelve-month deliveries (Exh. Unitil-JDS-1, at 14 (electric)).

The Company's proposal will shift the financial risk of changes in sales from its shareholders to its ratepayers because the Company's revenues will be reconciled for all changes in sales, including those resulting from weather and economic activity as well as from energy conservation and demand resources. However, the Department must consider not only the financial risks associated with the Company's revenue decoupling proposal and the risks attributable to rising commodity costs but also the reality of a carbon-constrained economy and our policy goal of removing barriers to the full implementation of demand resources. See, e.g., D.P.U. 10-70, at 43; D.P.U. 07-50, at 2; D.P.U. 07-50-A at 2.

We find that the Company's revenue decoupling proposal appropriately severs the link between revenues and sales for its electric division, which is consistent with the Commonwealth's commitment to eliminate the financial barriers that prevent the full engagement and participation of gas and electric distribution companies in efforts to reduce energy demand. Further, we find that the Company's revenue decoupling proposal for its electric division closely resembles the mechanisms approved for National Grid's electric operations in D.P.U. 09-39 and for WMECo in D.P.U. 10-70, which implement full revenue decoupling using a target revenue approach with annual reconciliations. The Department concludes that the need to upgrade and replace its capital infrastructure is a far more significant driver of electric distribution system costs than the addition of new customers, and that a revenue-per-customer approach would not address the Company's need for additional revenue to support its distribution system and provide quality electric service to customers. See D.P.U. 10-70, at 42-43; D.P.U. 09-39, at 73-74.

As such, we decline to impose a revenue-per-customer approach here and instead we approve the Company's target revenue proposal to fully decouple its revenue from its sales. We will factor in the shifting of risk inherent in the approved mechanism as we consider the need for review and reporting requirements, as well as the Company's proposals for both the CCAM and its ROE.

b. Oversight of RDM Adjustments

Both the Attorney General and DOER recommended that the Department impose annual reporting requirements on Fitchburg, similar to those implemented with the approval of WMECo's revenue decoupling mechanism. See, e.g., D.P.U. 10-70, at 43-44. Revenue decoupling is a significant departure from the traditional ratemaking paradigm and, therefore, we find that ongoing review is appropriate. Annual reporting requirements will permit the Department and intervenors to closely monitor the various effects of the Company's proposal over time. Therefore, we direct the Company to include in its annual RDM filings, for each residential, commercial, industrial, and street lighting customer class: (1) monthly customer counts; (2) monthly kWh sales; (3) weather normalized monthly kWh sales; (4) lost base revenue from energy efficiency programs for the most recent calendar year available; and (5) forecasted sales for the next two years.

c. Cap on Annual Revenue Decoupling Mechanism Adjustments

RDM adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve rate continuity. D.P.U. 09-39, at 87. In D.P.U. 10-70, at 45, we recognized that it may be prudent to limit the potential "rate shock" that customers may be exposed to from annual RDM adjustments, especially in service territories where difficult economic circumstances may make customers particularly vulnerable to adverse impacts from large year-to-year rate increases.

Here, Fitchburg has proposed a one percent cap, based on total revenue, on annual RDM adjustments for its electric division (Exh. Unitil-JDS-1, at 18 (electric)). However, ENE argues that the Company's proposal for a one percent cap should be increased to three percent in order to limit the potential for intergenerational inequities (ENE Brief at 6 (electric)).

We find that the Company's proposed one percent cap is appropriate as it would limit large and potentially disruptive annual changes in rates. In addition, the Company's proposed carrying charge on deferrals of RDM adjustments (i.e., the prime rate) is low enough such that neither the Company's ratepayers nor its shareholders are likely to be substantially affected if deferrals accrue from time to time. Accordingly, we will not adopt ENE's proposal to increase the cap on annual RDM reconciliations to three percent. Going forward, we will continue to evaluate and monitor any changes that might violate our existing ratemaking goals and render this cap inappropriate. D.P.U. 10-70, at 45; D.P.U. 09-39, at 88; D.P.U. 09-30, at 117. The Department may review and modify the cap, as necessary, in the context of the Company's annual RDM adjustment filings.

d. Capital Cost Adjustment Mechanism

Fitchburg has proposed a CCAM that would allow the Company to adjust its annual target revenue to recover the incremental costs of all post-test year capital spending. The

CCAM would include Fitchburg’s additions to plant from a prior calendar year’s capital spending (net of retirements, positive and negative salvage value, and deductions for depreciation expense), not to exceed an annual cap of one percent, with any excess costs to be deferred for recovery through the CCAM until later years, with interest.

According to Fitchburg, once its rates are decoupled, it will not have the opportunity to use increased revenue from sales growth to finance its capital budget. Fitchburg states that unless its proposed CCAM is allowed, it will experience earnings erosion and be precluded from earning a fair rate of return (Company Brief at 108). Conversely, the Attorney General and DOER argue that: (1) the Company has not demonstrated that the CCAM is necessary to sustain system reliability or to finance Fitchburg’s capital budget; and (2) the CCAM is not consistent with Department precedent or revenue decoupling policy (Attorney General Brief at 17-19, 24, 26-28; DOER Brief at 4-5 (electric)). The Attorney General also argues that the CCAM unfairly shifts risk from shareholders to ratepayers and, therefore, could result in inefficient capital investment decisions (Attorney General Brief at 20-21).

In D.P.U. 07-50-A, at 48, the Department recognized that revenue decoupling would, all other things being equal, remove the opportunity for companies to earn additional revenue from sales growth between rate cases and that such additional revenue was used to pay for, among other things, increasing O&M costs as well as costs related to system reliability and capital expansion projects. The Department stated that it would consider company-specific proposals that adjust target revenue to account for capital spending and inflation but that a company would bear the burden to demonstrate the reasonableness of its proposal. D.P.U. 07-50-A at 50.

One of the Department's primary objectives in establishing a revenue decoupling mechanism is to better align distribution companies' revenues with their costs. D.P.U. 07-50-A at 11. However, before adopting a reconciling mechanism, the Department must closely examine how the mechanism will achieve its intended goals and how its implementation will affect rates and a company's financial well-being. D.P.U. 10-55, at 66 n.43, citing D.P.U. 07-50-A at 50.

The Department has allowed capital cost reconciling mechanisms in cases where a distribution company has adequately demonstrated the need to recover incremental costs associated with Department approved capital expenditure programs in between rate cases. D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, 79-80, 82; D.P.U. 09-30, at 133-134. For example, in D.P.U. 09-39, at 79-82, the Department found that National Grid had demonstrated that its annual electric depreciation expense would be inadequate to sustain the significant increase in capital spending that the company required in order to maintain a safe and reliable distribution infrastructure. The Department approved National Grid's proposed CapEx mechanism but also established an annual spending cap that would allow the company to recover only a portion of its forecasted annual capital budget. D.P.U. 09-39, at 79-82.[58]

[58] The Department imposed an annual cap on National Grid's CapEx based on a three-year average of its historic electric spending. Such cap will permit National Grid to recover between approximately 58 and 72 percent of its forecasted capital budget for 2010 through 2013. D.P.U. 09-39, at 79. Unlike Fitchburg's proposal, National Grid's approved cap does not permit the company to defer any excess costs over the cap for recovery through the CCAM until later years. Instead, National Grid must wait to recover these costs until its next rate case. D.P.U. 09-39, at 82-83.

We found that such limit was necessary in order to protect ratepayers against the incentive a company has to over invest in capital infrastructure in order provide earnings to its shareholders. D.P.U. 09-39, at 81.[59]

Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve capital recovery mechanisms as a component of revenue decoupling. For example, in D.P.U. 10-70, at 47-48, the Department declined to approve WMECo's proposal for a capital recovery mechanism because the company did not demonstrate that there was a reasonable expectation of positive sales growth, absent decoupling.

For the reasons discussed below, we decline to adopt the Company's proposed CCAM.[60] First, the Company has failed to demonstrate that its proposed CCAM is necessary to recover incremental costs associated with its anticipated capital expenditures in between rate cases. Fitchburg's proposed CCAM is significantly broader in scope than National Grid's

59 Although capital recovery mechanisms are inherently at odds with the principle of regulatory lag, the Department also found that a limit on the CapEx recovery mechanism would preserve some of the regulatory incentives associated with regulatory lag. D.P.U. 09 39, at 80.

60 Although we need not reach it here, we note that Fitchburg's proposed annual capital recovery limit on the CCAM, which is based on the Company's average electric capital spending between 2007 and 2009, is inflated because it is based on an average that includes the abnormal capital expenses incurred as a result of Winter Storm 2008 (Exhs. DPU-23-2 (electric); DPU-23-13 (electric); AG-9-35, Att. (electric)).

approved CapEx mechanism. Fitchburg's annual depreciation expense of $4,686,062, which includes $4,303,893 of depreciation expense related to base distribution and $382,169 of depreciation expense related to internal transmission, would by itself provide the Company with between approximately 61 and 65 percent of its forecasted 2011 to 2015 capital budget (Exhs. Sch. Unitil-TPM-1 (electric); Unitil-MHC-4, at 3 (Supp. 3) (electric); see also Section X.F, below). As a percentage of its capital assets, Fitchburg's depreciation expense will provide almost the same proportion of dollars for Fitchburg's capital investments as the CapEx mechanism provides for National Grid's electric operations' capital investments (Exh. Sch. Unitil-TPM-1 (electric)); see also D.P.U. 09-39, at 79.

Further, the evidence in this proceeding does not show that, absent revenue decoupling, Fitchburg is likely to sustain positive growth in sales in the coming years. Instead, the evidence shows two competing trends with respect to Fitchburg's sales growth: (1) the Company's kWh sales have declined steadily over the past five years; and (2) the Company's sales appear to have recovered somewhat in 2010, as the overall economy rebounded from recession (Exh. DPU-5-1, Att. 2, at 1; Tr. 8, at 984-985).

The Company's own testimony has been conflicting as to the likelihood that Fitchburg will sustain positive sales growth in the future. The Company states that there are minimal long-term prospects for future sales growth within its service territory but it expects a short-term post-recession rebound in kWh sales with growth in the range of two to five percent in 2011 and 2012 (Exh. Unitil-TPM-1, at 5 (electric); Tr. 8, at 984-988). The Company also testified that growth in the Company's sales will likely continue to be controlled by economic circumstances both within and outside of the Company's service territory (see e.g., Tr. 8, at 979-989). Such circumstances are beyond Fitchburg's control and highly uncertain.

While the Company asserts that post-rate case increases in sales growth have helped to fund its capital budget in past years, it has provided insufficient evidence that these increases have been a reliable source of financing for capital costs or that the CCAM would be an appropriate substitution. For example, the Company has not experienced post-rate case increases in sales growth on a consistent basis but, even when it has, such growth has been short-lived (Exhs. DPU-5-1, Att. 2, at 1; DPU-5-8 (electric); Tr. 8, at 983-985). The one factor that has led the Company to seek rate relief from the Department in past years is declining sales and associated drops in revenue, which will be eliminated by revenue decoupling (see e.g., Tr. 8, at 984-985).

For all of these reasons, we find that the Company has not demonstrated that an additional reconciliation mechanism is warranted or is in the best interests of ratepayers. Specifically, we find that Fitchburg has failed to demonstrate that there are extraordinary circumstances, by virtue of revenue decoupling, price volatility, effect on earnings, or any other cost driver that preclude the Company from acquiring sufficient capital to make required infrastructure investments. As a result, we decline to approve the Company's proposed CCAM adjustment to the target revenue for its electric division.

It is important to emphasize that the Department makes no determination here regarding the optimal level of capital investments that the Company should make in order to ensure safe and reliable service for its customers, and we expect gas and electric distribution companies to make all necessary capital investments to that end. Fitchburg appears to be making reasonably steady annual capital investments and expects to spend between $7.3 and $7.7 million on such investments in each of the next five years (Exh. Sch. Unitil-TPM-1 (electric)). We recognize that the Company has recently replaced a significant portion of its electric distribution infrastructure as a result of Winter Storm 2008 and it is developing new programs to maintain its distribution system (Exh. DPU-11-5, Att. 1 (electric)). These are recent changes, however, and it will take time to fully evaluate their effects on the Company's capital budget.

In the event that the Department declines to approve the CCAM, Fitchburg proposed that its revenue decoupling mechanism for its electric division be modified to exclude revenue from new customers added after the test year in order to ensure that it has adequate revenue for its future capital investments, including the costs to connect new customers (Company Brief at 103 n.12). We find that this alternative proposal is inequitable. When customers leave the system, the rates of remaining customers would increase in order to compensate the Company for any losses; however, if new customers are added to the system, the Company would retain all of the benefits. The Company has presented no evidence that this proposal is in the best interest of ratepayers or consistent with the Department's policy to align a distribution company's financial interests with the efficient deployment of demand resources. For these reasons, we decline to approve the Company's alternate proposal.

e. Conclusion

We find that the Company's revenue decoupling mechanism for its electric division will sever the link between revenue and sales by reconciling target revenue with actual revenue, on an annual basis. In addition, we find that the Company's revenue decoupling mechanism is designed such that it appropriately aligns the Company's financial interests with the efficient deployment of demand resources and will ensure that the Company is not harmed by decreases in sales associated with the increased use of demand resources. D.P.U. 07-50-A at 11; D . P. U. 07-50-B at 1, 2, 6. Further, we find that operation of the Company's revenue decoupling mechanism, with the inclusion of annual reporting requirements and a one percent cap on annual adjustments and without the inclusion of the CCAM will result in just and reasonable rates. Accordingly, the Company's proposed revenue decoupling mechanism for its electric division, as modified herein is approved.[61]

To the extent that the implementation of revenue decoupling may result in undesirable or unintended consequences that could result in unjust and unreasonable rates, the Department, on its own motion pursuant to G.L. c. 164, § 93, and its general supervisory authority pursuant G.L. c. 164, § 76, may determine that it is necessary to investigate the propriety of such existing rates.

61 Our discussion of the treatment of revenue associated with the electric division's recently-approved special contract is found below in Section VI.E.3.f. As set forth in greater detail below, Fitchburg will be permitted to retain the special contract customer's test year electric revenue in its target revenue, as proposed.

3. Revenue Decoupling of Gas Division

a. Introduction

Fitchburg proposes to implement a full revenue decoupling mechanism for its gas division with a three percent cap (based on the Company's total revenue) on annual rate adjustments in each season (i.e., peak and off-peak). Specifically, the Company proposes to use a revenue-per-customer approach whereby annual adjustments will reconcile the Company's actual revenue-per-customer to its target revenue-per-customer. Except for the Attorney General's objection to the Company's proposed method for treating special contract revenue, discussed below, no party has opposed the Company's proposed gas revenue decoupling mechanism.

b. Revenue-Per-Customer Targets

Fitchburg proposes to use a revenue-per-customer approach to implement revenue decoupling for its gas division (Exh. Unitil-JDS-1, at 15-19 (gas)). The Company has established separate revenue-per-customer targets for the heating and non-heating residential rate classes (Exh. Unitil-JDS-1, at 16 (gas)). Also, Fitchburg proposes to aggregate its C&I rate classes into one group and develop a target revenue-per-customer for the group (Exh. Unitil-JDS-1, at 16 (gas)).

In D.P.U. 07-50-A at 55, the Department directed each distribution company to propose a base rate adjustment mechanism that reconciles target revenue to actual revenue for each rate class. We find that it is appropriate for Fitchburg to establish different targets for its heating and non-heating residential rate classes because of their differing consumption levels. D.P.U. 07-50-A at 55; see also D.P.U. 10-114, at 23-24; D.P.U. 10-55, at 41; D.P.U. 09-30, at 89-91. Therefore, the Company's proposal to establish separate revenue-per-customer targets for heating and non-heating residential rate classes is consistent with this method.

With respect to C&I rate classes, the Department has determined that the potential for customers to migrate from one C&I rate class to another could cause any class-specific revenue-per-customer targets to become unrepresentative of the cost to serve that class. D.P.U. 09-39, at 90. In addition, such customer migrations between rate classes could provide perverse incentives to the Company to encourage increased throughput because the target revenue-per-customer will be higher for the larger C&I rate classes. D.P.U. 09-39, at 90. Accordingly, the Department has approved proposals to aggregate C&I rate classes into one group and develop one base revenue-per-customer benchmark for that group. D.P.U. 10-114, at 24; D.P.U. 10-55, at 41; D.P.U. 09-30, at 90-91. For the same reasons, the Department approves Fitchburg's proposal to develop a target revenue-per-customer for all customers within its C&I customer classes.

c. Revenue Decoupling Mechanism Adjustments

i. Peak and Off-Peak Seasons

Fitchburg proposes to make separate RDM adjustments to reconcile its target revenue for the peak and off-peak seasons (Exh. Unitil-JDS- 1, at 19 (gas)). We find that Fitchburg's proposal is reasonable because it is consistent with the Company's existing method of reconciliations for the LDAF and CGAF. See, e.g., M.D.P.U. Nos. 123 and 145. The Department has approved similar proposals from other gas distribution companies. D.P.U. 10-114, at 25; D.P.U. 10-55, at 41-42; D.P.U. 09-30, at 91. For these same reasons, we approve the Company's proposal to use separate RDM adjustments to reconcile revenue for the peak and off-peak seasons.

ii. Three Percent Cap

As proposed, the Company's RDM adjustments may not exceed three percent of total revenue from firm sales and transportation throughput for the most recent peak or off-peak periods, with transportation revenue to be adjusted by imputing the Company's cost of gas charges for the period (RR-DPU-67, Att. 3, at 150 (proposed M.D.P.U. No. 159, Sheet 3)). Any RDM adjustments that exceed the cap would be deferred for recovery until the subsequent same season, with the deferred balance accruing interest at the prime rate calculated in accordance with 220 C.M.R. § 6.08(2) (RR-DPU-67, Att. 3, at 151 (proposed M.D.P.U. No. 159, Sheet 4)).

In D.P.U. 07-50, at 12, the Department found that a revenue decoupling proposal must "be consistent with Department precedent related to rate continuity, fairness, and earnings stability." The Department finds that applying a cap to the Company's RDM adjustments is consistent with this directive. Without such a cap, large RDM adjustments could occur, thereby violating the Department's rate structure goal of rate continuity. See D.P.U. 10-70, at 45; D.P.U. 10-55, at 43; D.P.U. 09-39, at 85-86; D.P.U. 09-30, at 114; New England Gas Company, D.P.U. 08-35, at 221 (2009); D.P.U. 92-78, at 116; D.P.U. 88-67 (Phase I) at 201.

To determine the appropriate cap on RDM adjustments, the Department must balance its goal of promoting the deployment of demand resources with its rate structure goals including rate continuity. D.P.U. 10-70, at 45; D.P.U. 10-55, at 43; D.P.U. 09-39, at 87; D.P.U. 09-30, at 116; see also D.P.U. 07-50-A, at 24. The Department has previously stated that RDM adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but capped in order to preserve rate continuity. D.P.U. 10-70, at 45; D.P.U. 10-55, at 43; D.P.U. 09-39, at 87. In balancing these concerns, the Department has previously imposed a three D.P.U. 10-114, at 26; D.P percent cap on annual RDM adjustments for gas companies. D.P.U. 10-114, at 26; D.P.U. 10-55, at 43; D.P.U. 09-30, at 116-117.

Based on the strong correlation between gas consumption and temperature, annual revenue for Fitchburg's gas division could vary widely as a result of year-to-year changes in weather. Without any cap, Fitchburg's gas customers could be subject to overly large annual RDM adjustments in rates. With too small a cap, customers could be burdened by RDM adjustments that have been deferred for recovery until later years. We find that the Company's proposed three percent cap, which would be calculated based on its total revenue (i.e., peak or off-peak season revenue from distribution rates, LDAC revenue, and gas commodity revenue), strikes an appropriate balance between promoting the deployment of demand resources and preserving the Department's overall rate structure goals, including rate continuity.

Because RDM adjustments will be reconciled from one season to another, it is appropriate to continually evaluate and monitor the RDM adjustments for any changes that could violate our existing ratemaking goals and render a three percent cap inappropriate. Accordingly, the Department will review, reevaluate, and modify the three percent RDM adjustment cap, as necessary, during the Company's peak and off-peak season RDM adjustment filings. See D.P.U. 10-114, at 27; D.P.U. 10-55, at 44; D.P.U. 09-30, at 117.

d. Treatment of New Customers

The Company proposes to exclude new customers (i.e., customers who are connected to the Company's system after the test year) and the associated revenue from its calculation of the number of customers and RDM adjustments until the Company's next rate case (Exh. Unitil-JDS- 1, at 17, 19 (gas)). The Company states that if new customers are included in the RDM, the cost-benefit analyses of an added customer could be distorted in ways that that could discourage the Company from adding customers, which would be harmful to the environment and local economy (Exh. Unitil-JDS- 1, at 17 (gas)).

With regard to the ratemaking treatment of incremental revenue from new customers after rates have been set in a base rate proceeding, long-standing Department precedent allows a company to retain those incremental revenues until that company's next general rate case. D.P.U. 10-55, at 45-46; D.P.U. 09-30, at 94 & n.50; Bay State Gas Company, D.T.E. 05-27, at 75, 79, 80 (2005); Boston Gas Company, D.T.E. 03-40, at 48 (2003); Boston Gas Company, D.P.U. 89-180, at 16-17 (1990); D.P.U. 88-67 (Phase I) at 282-284. In our prior decisions on revenue decoupling, the Department determined that, once revenue decoupling has been implemented, it is appropriate to permit a gas distribution company to retain incremental revenue from new customers added after the test year in order to preserve a company's incentive to add new customers, which should, in the long-term, reduce a company's average cost of distribution service. See D.P.U. 10-55, at 45-46; D.P.U. 09-30, at 98-99.[62] Thus, consistent with Department precedent, we will allow Fitchburg to retain incremental revenue from new customers until its next rate case by not including new customers in the calculation of RDM adjustments. The Company is directed to separately track the gas usage of new customers during the peak and off-peak seasons, as well as the cost to connect new customers by rate class, and report such information as part of its seasonal RDM adjustment filing. See, e.g., D.P.U. 10-55, at 46-47; D.P.U. 09-30, at 100-101.

e. Customer Conversions from Non-Heating to Heating

Fitchburg proposes to retain incremental revenues associated with residential customer conversions from the non-heating rate class to the heating rate class (Exh. Unitil-JDS-1, at 17 (gas)). Beginning in the month during which a customer conversion occurs, the Company would decrease the non-heating customer count and increase the heating customer count by one customer each, and it would retain the additional revenue-per-customer amount (Exh. DPU-7-14 (gas)).

[62] 62 A gas distribution company 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; D.P.U. 88-67 (Phase I) at 282-284. 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 D.P.U. 89-180, at 16-17.

In D.P.U. 09-30, at 103, the Department directed Bay State to include in its calculation of RDM adjustments the additional revenue-per-customer from any residential non-heating customer who converts to heating service as long as the conversion did not require any capital investment by Bay State; if the conversion did require Bay State to first make capital investments, it was allowed to retain all additional revenue-per-customer. D.P.U. 09-30, at 103. However, in more recent revenue decoupling Orders, we have allowed gas distribution companies to retain additional revenue from residential customer conversions from the non-heating class to the heating class in order to provide an incentive for the company to pursue activities that have beneficial effects on the environment and lower long-term costs to customers. D.P.U. 10-114, at 30; D.P.U. 10-55, at 50.

The Department currently allows gas distribution companies to retain, to some extent, additional distribution revenues associated with adding new customers to their distribution systems. Treating customer conversions in the same manner will ensure that benefits ultimately flow to customers by increasing the total volume of gas consumption on the distribution system, thereby spreading costs out across a larger pool and lowering distribution rates in the Company's next base rate proceeding.

We find that the Company's proposed treatment of customer conversions will ensure that there is no disincentive for the Company to facilitate such conversions. Also, we find that this proposal will ensure that the general public enjoys the environmental benefits of a conversion from electricity or oil-based heating to natural gas. D.P.U. 10-55, at 49-50. Accordingly, we approve Fitchburg's proposal to retain the additional revenue-per-customer associated with residential customer conversions from non-heating to heating classes.

Consistent with the reporting requirements adopted for NEGC in D.P.U. 10-114, at 30-31, we direct the Company to provide the following information in each of its semi-annual RDM adjustment filings: (1) the number of customers migrating from one rate class to another; (2) the cost to convert residential customers from the non-heating to the heating class; (3) the reduction in the number of existing customers by rate classes; (4) the addition of new customers by rate classes; and *(5)* an analysis of the effects on Fitchburg customers' consumption behavior pursuant to revenue decoupling.

f. Special Contract Revenues

The Company has proposed a specific treatment of revenues resulting from the gas and electric special contracts approved by the Department in Fitchburg Gas and Electric Light Company, D.P.U. 11-EC-1, Stamp-Approval (July *25*, 2011); Fitchburg Gas and Electric Light Company, D.P.U. 11 -GC-3, Stamp-Approval (July 25, 2011). If the special contract customer consumes the volume of gas anticipated by the contract for gas, the calculation of RDM adjustments for both the Company's gas and electric divisions will be affected in several ways. First, if the Company includes the special contract revenues within the RDM rate adjustments for its electric division, the Company would be compensated by its customers for the expected loss of revenue resulting from the special contract customer's self-generation activity and reduced electricity purchases. This compensation will be in an amount equal to the difference between test year revenue from the contract customer and the smaller amount of revenue expected from the contract customer for standby service pursuant to the special contract (Exhs. Sch. JDS-3 (electric); AG-1-99 (confidential) (electric); AG-26-4, Att. (confidential) (electric); *AG-26-5*, Att. (confidential) (electric)). In addition, the Company would continue to recover the target revenue-per-customer for each customer in its gas division, which would have been determined in part by the inclusion of test year revenue from the special contract customer. If the special contract customer ceases to be a gas customer pursuant to a tariff, it would decrease the Company's C&I customer count for its gas division by one, which would represent a lost C&I revenue-per-customer amount of approximately $4,200 per year (Exh. Sch. JDS-2 (gas)). The remaining gas customers' rates include the cost to serve the special contract customer and will reconcile the decrease in revenue-per-customer caused by the exclusion of the special contract customer's revenue from the RDM adjustment (Exh. Sch. JDS-3 (gas)). However, Fitchburg would retain all gas revenue received from this customer pursuant to the special contract for gas, which is expected to substantially exceed the amount from the test year, because such revenue would be excluded from the RDM adjustments for the gas division (Exh. AG-20-3 (gas)).

The Company claims that without the ability to retain incremental revenue from special contracts between base rate proceedings, it would have no incentive to develop any special contracts, which benefit all customers by retaining large C&I customers on the its gas and electric distribution system (Company Brief at 129). Alternatively, the Attorney General claims that, if approved, Fitchburg's proposal will allow it to collect windfall profits by transferring customers from tariff service to special contract service and these profits will likely flow to shareholders instead of ratepayers (Attorney General Brief at 189).

To establish rates, the Department relies on an historic twelve-month test year that, once adjusted for known and measurable changes, will serve as a proxy for future operating results. Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); Eastern Edison Company, D.P.U. *1580*, at 13-17 (1984). Changes in revenues associated with fluctuations in customer counts or level of consumption that occur after the test year are generally disregarded in the rate-setting process because such changes may also require corresponding adjustments to the cost of service in order to maintain a representative balance between a company's costs and revenues. 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 Department also has found that 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, warrants a departure from this standard practice. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 80 (2002).[63]

[63] Known and measurable changes to revenues and expenses are those that, based on the record evidence, have taken place or will take place and are quantifiable. The criterion used to assess the significance of variations in "ebb and flow" is typically the change to a company's total distribution operating revenue. See, e.g., D. T . E. 02-24/25, at 80; D.T.E. 99-118, at 18.

The Department has previously found that distribution companies must have the proper financial and regulatory incentives to, among other things, foster the development of renewable energy and distributed generation within Massachusetts. D.P.U. 07-50-A at 2. However, this goal must be balanced with the objective to decrease energy costs to customers through energy efficiency and demand resources. D.P.U. 07-50-A at 7, 23. The Department also has determined that post-revenue decoupling, it is appropriate 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, which should, in the long run, reduce a company's average cost of distribution service. See D.P.U. 10-55, at 45-46; D.P.U. 09-30, at 98-99.

The Company's proposed treatment of its special contract revenues is problematic because the special contract customer at issue is neither a new customer nor will its revenue be "lost" when the special contracts take effect as proposed. Accordingly, the Company's proposal represents basic transfer payments from the customers of both the electric and gas divisions to the Company because, while the bulk of the cost of serving the special contract customer would remain in base distribution rates for both the electric and gas divisions, the Company's revenue would change in three ways. First, customers in the Company's electric division (including the special contract customer), would have to bear the shortfall of the special contract customer's reduced electric revenue through future RDM adjustments. Second, customers in the same gas rate class as the special contract customer would have to bear the cost to serve the customer through base distribution rates, while the special contract customer's revenue-per-customer contribution, as established by the test year, would be "lost." Third, the Company would receive an increased amount of gas revenue directly from the special contract customer as a result of its installation of self-generating equipment fueled by natural gas. Each of the foregoing outcomes is purely a function of Fitchburg's proposed revenue decoupling design and its associated targets; the special contracts will not have any adverse effects on Company's risk profile.

In order to address these concerns, we direct the Company to remove the special contract customer's test year gas revenue (which is known and measurable) from the revenue requirement for its gas division. This will appropriately reduce Fitchburg's revenue-per-customer targets so that its other gas customers will not bear the costs associated with serving the special contract customer, whose costs will be fully recovered outside of the RDM adjustments. Fitchburg will be permitted to retain the special contract customer's test year electric revenue in its target revenue, as proposed.

We expect that this treatment will maintain a strong financial incentive for the Company to promote distributed generation to its existing customers without sacrificing the goal of reducing costs for all customers. During the Company's next base rate proceeding, Fitchburg's customers will receive the full cost reduction benefits associated with the special contract customer's adoption of onsite self-generation.

g. Revenue Decoupling Mechanism Adjustment Filings

We find that it is appropriate for the Company to provide a consistent and on-going record of all relevant information so that the Department can closely monitor the implementation of Fitchburg's revenue decoupling mechanism for its gas division. D.P.U. 10-70, at 43-44. In addition to the reporting requirements discussed above regarding the tracking of new customers and of residential customer conversions from the non-heating class to the heating class, we direct the Company to report to the Department as part of its annual RDM adjustment filings: (1) monthly customer counts by rate class and rate group; (2) monthly therm sales; (3) weather normalized monthly therm sales; (4) lost base revenue from energy efficiency programs for the most recent calendar year available; and (5) forecasted sales for the next two years.

Finally, as the Company has not included language regarding interim filings in its tariff, we direct the Company to modify its proposed revenue decoupling tariff for the gas division, M.D.P.U. No. 159, to include a provision stating that the Company shall make an interim filing with the Department if its actual revenue exceeds a threshold of ten percent above or below its target revenue level. See, e.g., D.P.U. 07-50-A at 5, 63, 87.

h. Conclusion

The Department finds that the Company's proposed revenue decoupling mechanism for its gas division is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B. We find that the proposed revenue decoupling mechanism appropriately aligns the financial interests of the Company with the efficient deployment of demand resources and will ensure that the Company is not harmed by decreases in sales associated with the increased use of demand resources. Further, we find that operation of the Company's proposed RDM adjustments will result in just and reasonable rates. Accordingly, Fitchburg's proposed gas revenue decoupling mechanism is approved as modified herein.

To the extent that the implementation of revenue decoupling may result in undesirable or unintended consequences that could result in unjust and unreasonable rates, the Department, on its own motion pursuant to G.L. c. 164, § 93, and its general supervisory authority pursuant to G.L. c. 164, § 76, may determine that it is necessary to investigate the propriety of such existing rates.

VII. TARGETED INFRASTRUCTURE REPLACEMENT FACTOR

A. Introduction

Fitchburg proposes a targeted infrastructure replacement factor ("TIRF") as a ratemaking mechanism to recover the revenue requirement associated with the replacement of: (1) non-cathodically protected steel ("bare steel") distribution mains and services; and (2) small diameter (eight inches or less) cast/wrought/ductile iron (collectively "small diameter iron") distribution mains; and (3) other eligible facilities included in the Company's targeted infrastructure replacement program (Exhs. Unitil-JDS- 1, at 21-23, 35-36 (gas); Unitil-TPM- 1 at 32 (gas)).[64] The Company proposes a tariff, captioned as "Targeted Infrastructure

[64] The TIRF eligible facilities include investments made into plant accounts: (a) 367 (Mains – Transmission); (b) 376 (Mains – Distribution); (c) 369/378 (Measuring and Regulating Station Equipment); (d) 380 (Services); (e) 381 (Meter Purchases); (f) 382 (Meter Installations); and (g) 383 (House Regulators) (Exhs. Unitil-JDS-1, at 23 (gas); DPU-10-1 (gas); RR-DPU-67, Att. 3, at 156 (proposed M.D.P.U. No. 160, Sheet 3)). The Company explained that eligible facilities include bare steel and small diameter iron distribution mains, including any connected facilities such as services, meters or regulators that must be installed or replaced to enable the main replacement to be operational (Exh. Unitil-JDS-1, at 22 (gas)); RR-DPU-67, Att. 3, at 156 (proposed M.D.P.U. No. 160, Sheet 3)). Bare steel and cast iron pipelines are considered leak prone (Exh. Unitil-TPM-1, at 27 (gas)). See also, D.P.U. 10-114, at 55.

Replacement Factor, Schedule TIRF" that specifies, among other things, the purpose, applicability, effective date,[65] eligible facilities, TIRF savings offset, limitations on revenue requirement recovery, and formula for calculating the annual TIRF charges for recovery in rates (Exh. Unitil-JDS-1, at 29 (gas); RR-DPU-67, Att. 3, at 154-160 (proposed M.D.P.U. No. 160, Sheets 1-7)).

The Company proposes that the revenue requirement to be recovered through the TIRF be calculated to include return on year-end cumulative rate base associated with TIRF eligible facilities plus the associated depreciation and property taxes (Exh. Unitil-JDS-1, at 23-24 (gas); Sch. JDS-8 (gas); RR-DPU-67, Att. 3, at 154 (proposed M.D.P.U. No. 160, Sheet 1)). Further, the Company further proposes that the return on rate base be calculated at the pre-tax rate of return approved in the instant proceeding (Exh. Unitil-JDS-1, at 23-24 (gas); RR-DPU-67, Att. 3, at 158 (proposed M.D.P.U. No. 160, Sheet 5)).

Fitchburg proposes that the TIRF revenue requirement be reduced by an operations and maintenance savings ("O&M offset") to reflect the Company's reduced leak repair activity as a

65 The proposed date on which the annual TIRF becomes effective in rates is November 1st of each year (Exh. Unitil-JDS- 1, at 26 (gas); RR-DPU-67, Att. 3, at 154 (proposed M.D.P.U. No. 160, Sheet 1)).

result of the infrastructure improvements (Exh. Unitil-JDS- 1, at 25-26 (gas); RR-DPU-67, at 55, 158 (proposed M.D.P.U. 160, Sheets 2, 5)). The Company proposes that the O&M offset be calculated as the product of the number of miles of bare steel and small diameter iron distribution mains replaced during a calendar year and the cost of repair per mile (Exhs. Unitil-JDS-1, at *25* (gas); Sch. JDS-8 (gas); RR-DPU-67, Att. 3, at 155 (proposed M.D.P.U. No. 160, Sheet 2)). The Company proposes a cost of repair of $2,934 per mile based on a three-year average of the cost of repair (Exhs. Sch. JDS-7 (gas); AG-17-8 (rev.) (gas)).[66]

Fitchburg notes that, although the amount of expenditures under its targeted infrastructure replacement program may vary from year to year, it proposes that the annual amount of the associated revenue requirement to be collected through rates be capped at 1.5 percent of the total actual gas revenues from firm sales and transportation throughput during the most recent calendar year (Exh. Unitil-JDS-1, at 26 n.23 (gas); RR-DPU-67, Att. 3, at 157 (proposed M.D.P.U. No. 160, Sheet 4)). Under Fitchburg's proposal, transportation revenues will be adjusted by imputing the Company's cost of gas charges (Exh. Unitil-JDS-1, at 26 (gas); RR-DPU-67, Att. 3, at 157 (proposed M.D.P.U. No. 160, Sheet 4)). The Company also proposes that any amount of the annual revenue requirement associated with its infrastructure investments in excess of the cap be eligible for recovery through the TIRF in the subsequent year (RR-DPU-67, Att. 3, at 157 (proposed M.D.P.U. No. 160, Sheet 4)).

[66] The Company's initially-filed cost of repair used in calculating the O&M offset was $2,586 per mile, but the Company subsequently revised it to $2,934 per mile based on a three-year average (Exhs. Sch. JDS-7 (gas); AG-17-8 (rev.) (gas)).

The Company proposes a two-step process to address concerns regarding the potential for: (a) "double recovery" of O&M costs as overheads in base rates and in the TIRF adjustments; and (b) the potential for shifts in overhead allocations between TIRF and non-TIRF capital projects (Exh. Unitil-JDS-1, at 28-29 (gas)). First, the Company proposes that, during the annual TIRF filing, the TIRF overhead rate[67] be capped by the baseline project overhead rate[68] approved in the instant proceeding (Exh. Unitil-JDS-1, at 28-29 (gas)). Second, Fitchburg submits that the TIRF overhead rate would be set equal to the overhead rate for non-TIRF related projects (Exh. Unitil-JDS-1, at 29 (gas)).

The Company's proposed TIRF is designed to adjust rates on an annual basis to recover, through the LDAC, the revenue requirement associated with the Company's investments in the TIRF eligible facilities (Exh. Unitil-JDS-1, at 23-24 (gas)). The Company proposes separate TIRF rate factors for the following three groups of rate classes: (a) residential (R-1, R-2, R-3 and R-4); (b) commercial and industrial ("C&I") low-load factor

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67 The TIRF overhead rate is the ratio of (1) indirect overhead costs applied to direct project costs for all of the TIRF construction projects in the TIRF year, to (2) the direct project costs for all of the TIRF construction projects in the TIRF year (Exh. Unitil-JDS-1, at 28-29 (gas)).

68 The TIRF baseline project overhead rate is the ratio of (1) indirect overhead costs applied to direct project costs for all of the construction projects in the test year, to (2) the direct project costs for all of the construction projects in the test year (Exh. Unitil-JDS-1, at 28-29 (gas)).

("LLF") (G-41, G-42, and G-43); and (c) C&I high-load factor ("HLF") (G-51, G-52, G-53) (Exh. Unitil-JDS-1, at 24 (gas); RR-DPU-67, Att. 3, at 155 (proposed M.D.P.U. No. 160, Sheet 2)). The Company proposes that the cumulative TIRF revenue requirement be allocated to each of these rate groups using a TIRF mains and services allocator (Exh. Unitil-JDS-1, at 24 (gas)).

Fitchburg claims that the proposed TIRF is necessary to provide the Company sufficient revenues to invest in capital projects because its proposed RDM eliminates its ability to increase revenue through increased sales (Exh. Unitil-JDS-1, at 22 (gas)). The Company maintains that such inability to increase revenue through increased sales could result in earnings erosion, because its bare steel and small diameter iron mains replacement program will require a significant portion of the Company's gas division capital spending (Exhs. Unitil-JDS-1, at 22 (gas); Sch. JDS-5 (gas)).

The Company claims that its proposed TIRF is similar to the TIRF mechanism proposed by National Grid in D.P.U. 10-55, which included the recovery of investments on the replacement of small-diameter cast iron distribution mains and bare steel services (Exh. Unitil-TPM-1, at 36 (gas)).[69] The Company states that it intends to continue replacing a minimum of two miles of bare steel and cast-iron mains annually, noting that additional replacement may result from other requirements under 220 CMR § 113.00 et seq.,[70] such as encroachments caused by municipal projects (Exh. Unitil-TPM-1, at 36 (gas)).

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[69] The Company notes that only 2.2 miles, of a total of 66.55 miles of cast/wrought iron mains in its distribution system, have a diameter larger than eight inches (Exhs. Unitil-TPM-1, at 36 (gas); AG -4-2, Att. 11, at 1).

[70] The Department's regulations at 220 C.M.R. §113.00 et seq govern the operation, maintenance, replacement and abandonment of cast-iron pipelines that are used to distribute natural gas.

As of the 2009 year end, the distribution system in Fitchburg's territory included 263 miles of gas mains (Exh. AG-4-2, Att. 11 (gas)). The distribution mains consisted of 7.06 miles of bare steel, 126.76 miles of protected steel, 66.54 miles of cast and wrought iron, 1.92 miles of ductile iron and 60.67 miles of plastic mains (Exh. AG-4-2, Att. 11 (gas))[71] In addition, the Company had 12,021 total services as of the 2009 year end, consisting of 1,787 bare steel, 6,183 protected steel, 12 iron and 4,039 plastic services (Exh. AG-4-2, Att. 11 (gas)). During the period from 2001 to 2010, the Company replaced annually an average of 2.55 miles of bare steel and cast iron main (0.58 miles of bare steel and 1.97 miles of cast iron) (Exhs. AG-4-35 (gas); AG-4-36 (gas)). In the test year, the Company replaced 1.96 miles of cast iron main and 0.35 miles of bare steel main (Exhs. AG-4-35 (gas); AG-4-36 (gas)). This pace of replacement is in accordance with the pace of replacement stipulated in the compliance agreement, as modified, between the Department and the Company (Exh. AG-4-22, Atts. 1, 2 (gas))[72] The original compliance agreement, executed in

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[71] As of 2010 year end, there remained 6.01 miles of bare steel mains (Exh. DPU-11-3 (gas)).

[72] See Fitchburg Gas and Electric Light Company, D.T.E. 00-PL-05, Consent Order (2000).

April 2000, provides that, among others things, the Company, commencing with calendar year 2000, will annually replace two miles of cast iron mains (Exh. AG-4-22, Att. 1, at 1 (gas)). The compliance agreement as modified in March 2003 permits the replacement of up to one mile per year of bare steel as part of the two-mile requirement (Exh. AG-4-22, Att. 2, at 1 (gas))[73]

In addition, the Company replaced annually an average of 203.5 bare steel services during the period from 2001 to 2010, and made 194 bare steel service replacements during the test year (Exh. AG-4-28, Att. 1 (gas)).

B. Positions of the Parties

1. Attorney General

The Attorney General contends that the proposed TIRF is costly to ratepayers, unnecessary and provides the wrong incentives to the Company (Attorney General Brief at 39). She claims that the Company has not met its burden of proof to demonstrate that a TIRF is necessary, and therefore argues that the Department should deny the proposed TIRF (Attorney General Brief at 39).

[73] The event that triggered the Consent Order and the associated compliance agreement was a pattern of improper actions by a Company employee during the 1990s involving a lack of or improper testing of service lines. D.T.E. 00-PL-05, 2. More specifically, a supervisory employee was logging gas pressure testings for services that had not in fact been pressure tested (Tr. 14, at 1799). Upon discovery of these matters, the Company terminated the employee and reported the matter to the Department (Tr. 14, at 1799-1800). The Department's Pipeline Engineering and Safety Division investigated the matter, which subsequently resulted in the Department and the Company entering into a compliance agreement (Tr. 14, at 1799-1800). D.T.E. 00-PL-05, 2, 3.

The Attorney General argues that the Company has failed to support the need for an accelerated replacement program (Attorney General Brief at 30). She claims that as a result of a compliance agreement, the Company has been carrying on accelerated replacements since 2000 without a TIRF (Attorney General Brief at 30, citing Exh. AG-DO-CF-1, at 16 (gas)). The Attorney General observes that a decade of aggressive replacement leaves relatively few bare steel mains to replace (Attorney General Brief at 31).

The Attorney General adds that the Company has neither shown that a recovery mechanism is needed to support adequate infrastructure replacement nor tied the proposed replacement rate to a leak reduction target (Attorney General Brief at 31). She claims that data from the U.S. Department of Transportation, Pipeline Safety and Hazardous Material Safety Administration show that distribution systems with high proportions of leak-prone mains do not always have high leak rates (Attorney General Brief at 31-32).

The Attorney General claims that the Company has not provided cost-benefit, cost effectiveness, or value of service studies to support the need or usefUlness of the TIRF (Attorney General Brief at 32). She notes that the Company's position is that a cost-benefit study serves little purpose because the Company does not have the option not to conduct a needed replacement (Attorney General Brief at 32). The Attorney General asserts that the Department should reject this notion because it would mean that, under the Company's logic, all capital expenditures, regardless of rate impacts or customer benefits would be deemed prudent and the costs passed along to ratepayers (Attorney General Brief at 32; Attorney

General Reply Brief at 48). She adds that the Company cannot be trusted to properly use the funds without the full review of a rate case (Attorney General Reply Brief at 48). In addition, the Attorney General argues that the Company's proposal to recover the costs of replacing services not connected to bare steel main replacement projects ("independent services") is potentially wasteful and inefficient (Attorney General Reply Brief at 48).

The Attorney General contends that the only safeguard for ratepayers is the 1.5 percent cap proposed by the Company, and that all performance risk is shifted to the customers (Attorney General Brief at 32). She claims that the Company has provided no milestones or penalties in conjunction with its stated goal of replacing 50 percent of its leak-prone infrastructure within 18 years (Attorney General Brief at 33). Furthermore, she argues, approval of a TIRF would reduce the regulatory lag that incentivizes cost control to the detriment of ratepayers (Attorney General Brief at 36-37). Citing a report sponsored by the National Regulatory Research Institute, she argues that the use of a capital tracker mechanism reduces regulatory lag, eliminating a utility's motivation to reduce costs (Attorney General Brief at 36).[74]

The Attorney General claims that, in the event that the Department approves a TIRF for Fitchburg, it is only justifiable for safety-related projects, specifically for moving inside gas meters to the outside of buildings (Attorney General Brief at 34). The Attorney General contends that approval of a TIRF should be limited to the purpose of replacing all inside meters

[74] K. Costello, "How Should Regulators View Cost Trackers," National Regulatory Research Institute (Sept. 2009).

with outside meters, and that the Company should not be allowed to exercise its own judgment in the determination of which meters are moved outside (Attorney General Brief at 35; Attorney General Reply Brief at 48). Further, with respect to the removal of inside meters, the Attorney General proposes the establishment of a number of reporting requirements (Attorney General Brief at 35-36).

The Attorney General recommends modifications to the Company's proposal in the event that the Department approves a TIRF, to be consistent with recent Department decisions in which a TIRF was approved (Attorney General Brief at 37). Specifically, she recommends that the customer-impact cap be limited to one percent of base distribution revenues, consistent with the TIRF mechanisms approved for Bay State in D.P.U. 09-30 and for National Grid's gas operations in D.P.U. 10-55 (Attorney General Brief at 37). The Attorney General argues that the Company has not demonstrated that its ratepayers are in a better position financially compared to the ratepayers of Bay State and National Grid to incur the higher rates resulting from the higher revenue cap (Attorney General Brief at 37). In addition, she argues that any investment exceeding the cap should be recovered through traditional ratemaking treatment, i.e., in a subsequent base rate case (Attorney General Brief at 38). She notes that the Department rejected similar proposals by Bay State and National Grid to include amounts over the cap in the following year's TIRF calculation, requiring the additional amounts to be treated through the traditional regulatory approach (Attorney General Brief at 38). Finally, the Attorney General recommends that, if approved, the TIRF calculation should use the O&M cost offset based on the three-year average of the cost of repair (Attorney General Brief at 38).

2. DOER

DOER argues that the TIRF should be approved with the modifications recommended by the Attorney General (DOER Brief at *5* (gas)) .[75] DOER contends that the TIRF will enable a more accelerated pace of infrastructure replacement by allowing investments to be recovered in a timelier manner (DOER Brief at 4 (gas)). Further, DOER claims that the public interest requires the replacement of unprotected bare steel and small diameter cast iron pipe because those facilities are leak prone (DOER Brief at *5* (gas), citing D.P.U. 10-114, at 56). Finally, DOER asserts that the Company has failed to justify its proposal for its 1.5 percent cap, which is higher than the cap approved by the Department for other gas companies (DOER Brief at 6 (gas)).

3. Fitchburg

Fitchburg argues that its proposal is consistent with those previously approved by the Department in decoupling proceedings, and that the Company has "plainly made the case" for its proposed recovery mechanism for investment in bare steel and small diameter iron replacement programs (Company Brief at 115-117). The Company contends that the need for

[75] The Attorney General recommended that the Department reject the Company's proposal, but that if the TIRF were allowed, the following modifications should be made: (1) the customer-impact cap be set at one percent; (2) recovery of investment amounts in excess of the customer-impact cap be deferred until a future rate case; and (3) the Company be required to file annual TIRF documentation analogous to that set forth in D.P.U. 10-114 (Exh. AG-DED-1, at 35-36 (gas)).

bare steel and small diameter iron infrastructure replacement in its distribution system is as great as for any other company with a Department-approved TIRF (Company Brief at 120). The Company claims that the accelerated rate of bare steel and small diameter cast iron main replacement was established by a compliance agreement with the Department and addresses a public safety concern (Company Brief at 119). According to the Company, 40 percent of its annual capital spending budget is necessary for the replacement of bare steel and small diameter iron distribution infrastructure, which is non-revenue producing (Company Brief at 116). Further, the Company claims that without some measure of infrastructure investment recovery, it will experience “significant earnings erosion” because it would not retain revenue growth under decoupling (Company Brief at 116).

In addition, citing D . P. U. 10-114, the Company argues that its pre-decoupling success in replacing bare steel and small diameter iron infrastructure is not cause for the rejection of the proposed TIRF mechanism (Company Brief at 122). The Company notes that, in the past, it has relied on revenue growth to fund post test year additions to plant (Company Brief at 121). The Company maintains that revenue growth from existing customers will not be available to the Company under the decoupling proposal (Company Brief at 121). The Company argues that it has made a “well-reasoned and supported focus to target replacement of unprotected steel/cast iron services” (Company Reply Brief at 53). It argues that unprotected services potentially pose a greater threat to public safety than unprotected mains due to their proximity to buildings (Company Brief at 117; Company Reply Brief at 54). The Company adds that its replacement of independent services has increased three-fold since 2005 (Company Brief at 117; Company Reply Brief at 54, citing Exh. Unitil-TPM-1, at 35 (gas)).

The Company notes that a cost benefit analysis is unwarranted, because it is obligated to replace cast iron and bare steel mains, the investment is non-discretionary (Company Brief at 119). The Company challenges the Attorney General's assertion that meter move-outs are discretionary, stating that its policy is that when replacing the service, all inside meters are relocated unless it is impractical or not cost effective (Company Brief at 122). The Company also notes that inside meters are relocated on 90 percent of the services replaced, and that those meters left in place do not constitute the same level of risk, since they are no longer connected to the bare steel services that are the source of the leaks (Company Brief at 122, 123).

C. Analysis and Findings

The Department has previously allowed reconciling tariffs, such as the TIRF, in cases where a distribution company has adequately demonstrated the need to recover, between rate cases, incremental costs associated with Department-approved capital expenditure programs. D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. The Department has also approved TIRFs when they are designed to support an expedited replacement of a gas company's leak-prone distribution infrastructure. D.P.U. 10-114, at 34, 77; D.P.U. 10-55, at 121-122; D.P.U. 09-30, at 119, 133-135. The Department has done so to provide more certainty for, and more timely recovery of, the revenue requirement associated with capital expenditures for bare steel replacement between rate cases and to incentivize the company to expedite the replacement of the bare steel in its distribution system.

D.P.U. 10-114, at 34, 62, 77; D.P.U 10-55, at 67, 121; D.P.U. 09-30, at 133, 134. In these cases, the Department found that such accelerated replacement was desirable given the potential benefits to public safety, service reliability, and the environment. D.P.U. 10-114, at 56; D.P.U. 10-55, at 67; D.P.U. 09-30, at 133-34.

Here, the Company has failed to demonstrate a need for a special cost recovery mechanism to support an appropriate infrastructure replacement program. Unlike prior cases where the Department approved a TIRF, the Company here is not proposing to accelerate its rate of replacement if its TIRF proposal is approved. The record in this case shows that the Company has proposed to continue its current rate of replacement of a minimum of two miles of bare steel and cast iron mains annually, and that, at such pace of replacement, the Company expects to reduce its in-service inventory of bare steel and cast iron mains by 50 percent over 18 years (Exh. Unitil-TPM-1, at 36 (gas)). This pace of replacement is in accordance with the pace stipulated in the modified compliance agreement between the Department and the Company (Exh. AG-4-22, Atts. 1, 2 (gas)). Because the Company's current replacement program is consistent with its modified compliance agreement and the Company intends to maintain its current pace of replacement with or without the TIRF, we find that the TIRF is not designed to support an expedited replacement program and, therefore, there is no need for the Department to implement an incentive mechanism.

We also find that the Company has failed to adequately demonstrate the need to recover incremental costs between rate cases. The Company has argued that it needs the TIRF mechanism in order to prevent earnings erosion because its proposed RDM eliminates its current ability to increase revenue through increased sales (Exh. Unitil-JDS-1, at 22 (gas)). Without clear evidence that sales would have increased without decoupling, the Department has declined to approve cost recovery mechanisms. For example, in D.P.U. 10-70, the Department declined to approve WMECo's proposal for a capital reliability recovery clause because the company did not demonstrate that there was a reasonable expectation of positive sales growth, absent decoupling. D.P.U. 10-70, at 47-48. Similarly, as we note above in Section IV.E, the evidence in this proceeding does not show that, absent revenue decoupling, the Company is likely to sustain positive growth in sales in the coming years.[76] Therefore, based on all of the reasons set forth above, we decline to approve the Company's proposed TIRF mechanism.

The Company also has failed to demonstrate a reason for the Department to diverge from traditional ratemaking principles.[77] The Department gives careful consideration to the formation of any new cost reconciling mechanism. See, e.g., D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-86. Such consideration is warranted because extraordinary cost recovery

[76] The record in these proceedings shows that there was little or no growth in the Company's total annual revenues for years 2008 through 2010 (Exh. DPU-7-1, Att. 1, at 1 (gas)). Although total Company revenues increased from $27.040 million in 2005 to $29.228 million in 2006, and to $31.884 million in 2007, total revenues decreased from the 2007 level in 2008, 2009, and 2010 to $31.276 million, $29.341 million, and $29.803 million, respectively.

[77] The Department has stated that a TIRF rate recovery mechanism is not designed to supplant traditional ratemaking. D.P.U. 10-114, at 56-57; D.P.U. 10-55, at 122.

mechanisms can lessen the incentive of a utility to control its costs. Under traditional ratemaking practice, there is a time gap between when a utility incurs a cost and when the utility can account for the change in costs through new rates. This time gap is referred to as “regulatory lag,” and it provides a strong incentive for companies to invest wisely in capital projects, control costs, and therefore, reduce bill impacts to ratepayers. D.P.U. 09-39, at 80. Cost reconciling mechanisms, because they allow dollar-for-dollar recovery from ratepayers, substantially reduce, or in some cases may eliminate, benefits to ratepayers associated with regulatory lag. We find that in this case, traditional ratemaking policies will provide the Company with the appropriate incentive to make necessary infrastructure investments in a way that is efficient and equitable for both shareholders and ratepayers. D.P.U. 09-39, at 80-81.

The Department notes that, even though the Department denies a TIRF, the Company is required, at a minimum, to continue its replacement program at its current rate under the Company’s modified compliance agreement (Exh. AG-4-22, Atts. 1, 2 (gas)). As we have said before, timely replacement of aging infrastructure addresses a problem that threatens public safety and the integrity and reliability of infrastructure built and maintained to serve the public. D.T.E. 05-27, at 49; see also Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 13 (1998). This is a function of the Company’s basic public service obligation: to ensure that it delivers natural gas to its customers through a safe and reliable system at the lowest possible cost. Natural Gas Unbundling, D.T.E. 98-32-B at 5 (1999). A utility company’s obligation to fulfill safety requirements is absolute. D.T.E. 05-27 at 49;

Bay State Gas Company D.P.U. 92-111, at 10(1992). Thus, while we make no determination here regarding the Company's optimal level of capital investments, we expect that the Company will make all necessary capital investments to ensure safe and reliable service to its customers.[78]

VIII. RATE BASE

A. Introduction

Fitchburg reported a pro-forma test year total utility plant in service for its electric division of $96,396,343 (Exh. Sch. RevReq-4 (Supp. 3) (electric)). The Company reduced the test year total plant in service by $33,673,325 to account for accumulated depreciation, resulting in a net utility plant in service of $62,723,017 (Exh. Sch. RevReq-4 (Supp. 3) (electric)). Fitchburg further reduced the net utility plant in service by the following amounts: (1) $8,366,645 for deferred income taxes; (2) $257,699 for customer deposits; (3) $136,900 for customer advances; and (4) $767 for unclaimed funds (Exh. Sch. RevReq-4 (Supp. 3) (electric)). Finally, the Company added the following amounts to rate base: (1) $870,600 for materials and supplies inventories, excluding fuel; and (2) $899,873 for cash working capital (see Exh. Sch. RevReq-4 (Supp. 3) (electric)). Based on these adjustments, the Company determined that its total electric division rate base was $56,561,547 (see Exh. Sch. RevReq-4 (Supp. 3) (electric)).

78 Because we deny the TIRF, we need not reach the Attorney General's argument regarding inside meters. We note, however, that the record demonstrates that the Company is relocating inside meters on 90 percent of the occasions that it works on related services (Exh. AG-12-12, at 1 (gas)). We expect the Company to continue its practice of relocating inside meters whenever it works on the associated service.

Fitchburg reported a pro-forma test year utility plant in service for its gas division of $80,550,471 (Exh. Sch. RevReq-4 (Supp. 3) (gas)). The Company reduced the test year total plant in service by $27,101,498 to account for accumulated depreciation, resulting in a net utility plant in service of $53,448,973 (Exh. Sch. RevReq-4 (Supp. 3) (gas)). Fitchburg further reduced the net utility plant in service by the following amounts: (1) $3,825,668 for deferred income taxes; (2) $139,039 for customer deposits; (3) $21,532 for customer advances; and (4) $606 for unclaimed funds (Exh. Sch. RevReq-4 (Supp. 3) (gas)). Finally, the Company added the following amounts to rate base: (1) $361,343 for materials and supplies inventories; and (2) $999, 122 for cash working capital (see Exh. Sch. RevReq-4 (Supp. 3) (gas)). Based on these adjustments, the Company determined that its total gas division rate base was $50,822,593 (see Exh. Sch. RevReq-4 (Supp. 3) (gas)).

B. Plant Additions

1. Introduction

In its initial filing, Fitchburg identified all electric division capital projects that were completed between January 1, 2007 and December 31, 2009.[79] For each project, the Company provided the authorization number, a brief project description, the total amount authorized, the total amount expended, and the total amount closed to plant (Exh. Sch. Unitil-TPM-2

[79] Fitchburg's current electric rates include capital projects completed through the test year ending December 2006. See D.P.U. 07-71, at 27-41.

(electric); RR-DPU-34, Att. 2)). During the proceedings, the Company provided capital authorizations and closing reports for 44 projects with a cost greater than $50,000 (Exhs. DPU-10-6, Att. (electric); AG-1-19 (electric); AG-1-19, Att. 2, Parts 1-8 (Supp.) (electric); AG-27-3, Att. (electric); AG-27-5, Att. (electric); AG-27-6, Att. (electric)).

In its initial filing, Fitchburg identified all gas division capital projects that were completed between January 1, 2006 and December 31, 2009.[80] For each project, the Company provided the authorization number, a brief project description, the total amount authorized, the total amount expended, and the total amount closed to plant (Exh. Sch. Unitil-TPM-1 (gas); RR-DPU-34, Att. 1). During the proceedings, the Company provided capital authorizations and closing reports for 55 projects with a cost greater than $50,000 (Exhs. DPU-8-6, Att. (gas); AG-1-19 (gas); AG-1-19, Att. 2, parts 1-6 (Supp.) (gas); AG-19-2, Att. (gas); AG-19-4, Att. 1 (gas); AG-19-6, Att. (gas); AG-19-7, Att. (gas); AG-19-9, Att. (gas); AG-19-10, Att. (gas); AG-19-11, Att. (gas); AG-19-12, Att. (gas); AG-19-13, Att. (gas); AG-19-14, Att. (gas); AG-19-15, Att. (gas); AG-19-16, Att. (gas); AG-19-17, Att. (gas); AG-19-18, Att. (gas)).

2. Position of the Company

Fitchburg contends it has maintained detailed information on each electric and gas plant addition included in rate base since the Company's last base rate cases, including work order authorizations and closing reports (Company Brief at 41, 43). The Company argues that the

80 Fitchburg's current gas rates include capital projects completed through the test year ending December 2005. See D.T.E. 06-109, at 8-10.

work order authorizations and closing reports demonstrate that the costs of these additions were prudently incurred and, therefore, that the additions should be included in rate base (Company Brief at 41-44). No other party addressed the issue of plant additions on brief.

3. Analysis and Findings

The Department's standard of review for plant additions is that the expenditures must be prudently incurred and the resulting plant must be used and useful to customers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20, 25-27 (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 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. D.P.U. 93-60, at 24; D.P.U. *85-270*, at 22-23. 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. Dep't of Pub. Utils., 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. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996), citing D.P.U 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U 95-40, at 7 (1995), citing D.P.U 93-60, at 26; Mass. Elec. Co. v. Dep't of Pub. Utils., 376 Mass. 294, 304 (1978); Metro. Dist. Comm. v. Dep't of Pub. Utils., 352 Mass. 18, 24 (1967). In addition, the Department has stated:

> 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.

No intervenors have challenged the prudence of the Company's plant additions. Nevertheless, as noted above, the Company bears the burden of demonstrating through clear and convincing evidence that such plant investments were prudently made. D.P.U 95-40, at 7, citing D.P.U 93-60, at 26; 376 Mass. 294, 304; 352 Mass. 18, 24.

Between 2007 and 2009, Fitchburg completed 44 projects in its electric division with a total cost in excess of $50,000 (Exhs. Sch. Unitil-TPM-2 (electric); DPU-10-6, Att. (electric); AG-1-19 (electric); AG-1-19, Att. 2, Parts 1-8 (Supp.) (electric); AG-27-3, Att. (electric); AG-27-5, Att. (electric); AG-27-6, Att. (electric); RR-DPU-34, Att. 2). Between 2006 and 2009, Fitchburg completed 55 projects in its gas division with a total cost in excess of $50,000 (Exhs. Sch. Unitil-TPM-1 (gas); DPU-8-6, Att. (gas); AG-1-19 (gas); AG-1-19, Att. 2, parts 1-6 (Supp.) (gas); AG-19-2, Att. (gas); AG-19-4, Att. 1 (gas); AG-19-6, Att. (gas); AG-19-7, Att. (gas); AG-19-9, Att. (gas); AG-19-10, Att. (gas); AG-19-11, Att. (gas); AG-19-12, Att. (gas); AG-19-13, Att. (gas); AG-19-14, Att. (gas); AG-19-15, Att. (gas); AG-19-16, Att. (gas); AG-19-17, Att. (gas); AG-19-18, Att. (gas); RR-DPU-34, Att. 1). The Department has reviewed the data produced by the Company with respect to the aforementioned completed projects including all supporting documents such as capital budgets, authorizations, and closing reports. Based on our review of these data and supporting documentation, the Department finds that the Company acted prudently in estimating the costs associated with these projects, promptly revised the estimates as necessary, provided sufficient and reviewable evidence to demonstrate that it has controlled costs, and demonstrated that the reasons for any cost overruns include factors that could not have been reasonably anticipated during the preparation of the construction estimates. We find, therefore, that the project expenditures were prudent.

The Department considers plant to be "used and useful" if the plant is in service and provides benefits to customers. D.T.E. 98-51, at 9; Boston Gas Company, D.P.U *96-50* (Phase I) at 15 (1996). In the absence of extraordinary circumstances, the Department normally does not allow the relitigation of the used and usefulness of plant once it has been included in rate base. D.P.U. 93-60, at 43; D.P.U. 92-210-B at 14. No intervenors have challenged the Company's plant additions under the Department's used and useful standard. Based on our review, the Department finds that the Company has demonstrated that the plant is in service and provides benefits to customers (Exhs. Unitil-MHC-1, at 18 (electric); Unitil-MHC-1, at 13 (gas)).

Based on the above, we find that the Company has sustained its burden of proof and demonstrated that its proposed plant additions were prudently incurred and are used and useful. Accordingly, we will allow the cost of these projects to be included in rate base.

C. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including O&M expenses. These funds are either generated internally by a company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a cash working capital component to the rate base calculation.

Cash working capital costs have been determined through either the use of a lead-lag study or a conventional 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has previously relied on a 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase I) at 35.[81] However, as the 45-day convention was first developed in the early part of the 20th century, the Department has expressed concern that it no longer provides a reliable measure of a utility's working capital requirements because of the time it takes for money transactions to occur. D.T.E. 03-40, at 92, citing D.T.E. 98-51, at 15; D.P.U. 96-50 (Phase I) at 27. Therefore, the Department currently requires each gas and electric distribution company to either: (1) conduct a lead-lag study where cost-effective;[82] or (2) propose a reasonable alternative to a lead-lag study to develop a different interval. D.T.E. 03-40, at 92, citing D.T.E. 02-24/25, at 57.

[81] When a fully developed and reliable lead-lag study is not available, the Federal Energy Regulatory Commission ("FERC") applies a 45-day convention to determine the cash working capital allowance. Carolina Power & Light Co., 6 FERC 61, 154 at 61, 296 (1979). As a result, companies occasionally refer to the 45-day convention as the "FERC convention" (see, e.g., RR-DPU-17, Att.).

[82] 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, or a reasonable alternative to a lead-lag study. D.P.U. 07-71, at 47 n.34; D.T.E. 02-24/25, at 57 n.34.

2. Fitchburg's Lead-Lag Studies

a. Summary

Fitchburg conducted a lead-lag study to determine the net lag days associated with purchased power, external transmission, and electric operating expenses for its electric division; the Company conducted a separate lead-lag study to determine the net-lag days associated with borrowing funds to pay for purchased gas and gas operating expenses for its gas division (Exhs. Unitil-PMN-2E, Att. PMN-LL-2E; Unitil-PMN-2E, Att. PMN-LL-2G). The Company's lead-lag studies compare the timing difference between (1) the incurrence of costs by the Company and the Company's subsequent payment of such costs ("expense lead"), and (2) the receipt of service by customers and the customer's subsequent payment for these services ("revenue lag") (Exhs. Unitil-PMN-2E at 3-4; Unitil-PMN-2G at 3).

b. Expense Lead Factors

To determine its proposed cash working capital allowance, the Company first identified the following expense categories applicable to both its electric and gas divisions: (1) payroll expense; (2) payroll deductions; (3) regulatory commission expenses; and (4) other O&M expense (Exhs. Unitil-PMN-2E at 5-6, 9-11, Att. PMN-LL-2E; Unitil-PMN-2G at 5, 11, Att. PMN-LL-2G). In addition, the Company identified basic service expense and transmission costs as expense categories applicable to the electric division and purchased gas as an expense category applicable to the gas division (Exhs. Unitil-PMN-2E at 12, Att. PMN-LL-2E; Unitil-PMN-2G at 11-12, Att. PMN-LL-2G). The expense lag for both divisions also includes property taxes, payroll taxes, and unemployment taxes

(Exhs. Unitil-PMN-2E at 11; Unitil-PMN-2G at 11). The expense lead is reported as 21.60 days for the electric division and 21.92 days for the gas division (Exhs. Unitil-PMN-2E, Att. PMN-LL-2E at 1; Unitil-PMN-2G, Att. PMN-LL-2G at 1).

c. Revenue Lag Factors

According to Fitchburg, the revenue lag is calculated based on the time between the date when customers receive service and the date when they pay for service (Exhs. Unitil-PMN-2E at 4; Unitil-PMN-2G at 4). A revenue lag consists of four components: (1) a service lag; (2) a billing lag; (3) a collection lag; and (4) a revenue/expense float (Exhs. Unitil-PMN-2E at 6; Unitil-PMN-2G at 6). The Company's service lag is the average time span between (1) the mid-point of the customer's consumption interval, and (2) the time such usage is recorded by the Company for billing purposes and is calculated for all companies as one-half of an average month (i.e., 15.21 days) (Exhs. Unitil-PMN-2E at 7; Unitil-PMN-2G at 6-7). The billing lag is the time required to process and send out bills (Exhs. Unitil-PMN-2E at 7; Unitil-PMN-2G at 7). Fitchburg uses an automated meter reading system to read customer meters and it posts its meter reads daily for billing the next day and recording to accounts receivable the following day (Exhs. Unitil-PMN-2E at 7; Unitil-PMN-2G at 7). The Company reports the billing lag as 2.49 days for both divisions, taking into consideration the delay associated with weekends and holidays as well as the posting to accounts receivable (Exhs. Unitil-PMN-2E at 7; Unitil-PMN-2G at 7).

The collection lag represents the time delay between the posting of customer bills to accounts receivable and the Company's receipt of payment (Exhs. Unitil-PMN-2E at 8;

Unitil-PMN-2G at 7). The collection lag was calculated using the accounts receivable turnover method[83] and resulted in a collection lag of *37.25* days for the electric division and 52.21 days for the gas division (Exhs. Unitil-PMN-2E at 8, Att. PMN-LL-2E at 2; Electric Lead-Lag Study Workpapers at 4; Unitil-PMN-2G at 7-8, Att. PMN-LL-2G at 2; Gas Lead-Lag Study Workpapers at 4). Finally, the revenue float/expense accounts for: (1) the time difference between when funds are received from customers and when customer payments clear the banks and are available to a company; and (2) the time difference associated with a company's own vendor payments clearing the bank (Exhs. Unitil-PMN-2E at 8; Unitil-PMN-2G at 8).[84]

Fitchburg reports its revenue lag for the electric division as 54.90 days for operations and 54.95 days for purchased power and transmission (Exh. Unitil-PMN-2E, Att. PMN-LL-2E at 1, 4-5). The Company states that the revenue lag for the gas division is 69.88 days for operations and 69.91 days for purchased gas (Exh. Unitil-PMN-2G, Att. PMN-LL-2G at 1, 4).

d. Net Lag Factors

The arithmetic difference between the calculated revenue lag and the calculated expense lead is the net lag. The net lag represents the number of days that shareholders must provide funding for the Company's daily operations (Exhs. Unitil-PMN-2E at 5; Unitil-PMN-2G at 5). Fitchburg calculates the net lag days for its electric division as follows: (1) 15.75 days for

83 The accounts receivable turnover method calculates average daily revenues from the twelve months ending December 31, 2009 (Exhs. Unitil-PMN-2E at 8, Unitil-PMN-2G at 7-8).

84 Due to its complexity, the Company states that it did not account for revenue float in its cash working capital analysis (Exhs. Unitil-PMN-2E at 9; Unitil-PMN-2G at 8-9).

purchased power; (2) 25.95 days for external transmission; and (3) 33.30 days for O&M expenses (Exhs. Unitil-PMN-2E at 5, Att. PMN-LL-2E at 4-5). Fitchburg calculates the net lag days for its gas division as follows: (1) 29.92 days for purchased gas; and (2) 47.96 days for O&M expense (Exh. Unitil-PMN-20 at 5, Att. PMN-LL-2G at 4).

3. Position of the Company

The Company asserts that the Department requires utilities to either conduct a lead-lag study, where cost effective, or propose a reasonable alternative to a lead-lag study to develop an interval different than the 45-day convention (Company Brief at 40, citing D.T.E. 05-27, at 98; D.T.E. 03-40, at 92). The Company argues that performing lead-lag studies in these cases was appropriate because the cost of performing the two studies was only $43,210 but that its electric and gas customers experienced a net benefit as a result (Company Brief at 44, citing RR-DPU-17).[85] No other party addressed the Company's proposed cash working capital requirements.

4. Analysis and Findings

a. Introduction

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. Such funds are either generated internally or through

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85 Using a normalization period of four years, the Company calculates the net reduction to its revenue requirement as a result of performing the lead-lag studies as $24,228 (a negative $13,234 for gas and a positive $37,462 for electric) (RR-DPU-17, Att.).

short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; Western Massachusetts Electric Company, D.P.U. 87-260, at 22 (1988). The Department currently requires gas and electric distribution companies to conduct a lead-lag study where cost effective or propose a reasonable alternative to a lead-lag study to develop an interval other than the traditional 45-day convention. D.T.E. 02-24/25, at 57.

The Department has reviewed the Company's lead-lag studies, including all underlying calculations and assumptions. The Company developed separate cash working capital factors for the expense categories applicable to both divisions (i.e., payroll expense, payroll deductions, regulatory commission expenses, and other O&M expense) (Exhs. Unitil-PMN-2E at 5-6, Att. PMN-LL-2E; Unitil-PMN-2G at 5, 11, Att. PMN-LL-2G). In addition, the Company developed separate cash working capital factors applicable to basic service expense and transmission costs for the electric division, and a separate factor for purchased gas as an expense category applicable to the gas division (Exhs. Unitil-PMN-2E at 12, Att. PMN-LL-2E; Unitil-PMN-2G at 11-12, Att. PMN-LL-2G). The development of separate cash working capital factors for commodity-related expenses and distribution-related expenses is consistent with how the Department has historically treated cash working capital allowances. See D.P.U. 08-35, at 35; D.T.E. 02-24/25, at 51; D.P.U. 88-67 (Phase I) at 40-43.

b. Expense Lead Factors

We have reviewed the Company's calculation of its proposed expense lead factors. We find that the expense lead of 21.60 days for the electric division and the 21.92 days for the gas division have been properly calculated and are appropriate to use for the determination of the cash working capital requirements (Exhs. Unitil-PMN-2E, Att. PMN-LL-2E at 1; Electric Lead-lag Study Workpapers; Unitil-PMN-2G, Att. PMN-LL-2G at 1; Gas Lead-lag Workpapers).

c. Revenue Lag Factors

i. Introduction

We have reviewed the Company's calculation of its proposed revenue lag factors. We find that Company properly calculated the service lag and billing lag components of the revenue lag for both the electric and gas divisions (Exhs. Unitil-PMN-2E at 6, Att. PMN-LL-2E at 1; Electric Lead-lag Study Workpapers at 1; Unitil-PMN-2G at 6-7, Att. PMN-LL-2G at 1; Gas Lead-lag Workpapers at 1). Accordingly, we find that these results are appropriate to use for the determination of the cash working capital requirements. However, for the reasons discussed below, we conclude that the Company has failed to demonstrate that the proposed collection lags for its electric and gas divisions are appropriate.

ii. Proposed Collection Lag Factors

As noted above, the collection lag is a component of the Company's revenue lag (Exhs. Unitil-PMN-2E at 6; Unitil-PMN-2G at 6). The collection lag affects the Company's total cash working capital requirement and, therefore, it is essential to calculate the collection lag correctly in order to ensure that the Company collects an amount of cash working capital that meets, but does not exceed, its actual needs. See D.P.U. 10-55, at 204.

Fitchburg calculates a test year collection lag of *37.25* days for the electric division and 52.21 days for the gas division (Exhs. Unitil-PMN-2E at 8, Att. PMN-LL-2E at 2; Electric Lead-lag Study Workpapers at 4; Unitil-PMN-2G at 7-8, Att. PMN-LL-2G at 2; Gas Lead-lag Study Workpapers at 4)[86] The collection lags reported in the 2009 test year were significantly higher than the lags experienced in 2008 or 2010 (Exhs. Unitil-PMN-2E at 8, Att. PMN-LL-2E at 2; Electric Lead-lag Study Workpapers at 4; Unitil-PMN-2G at 7-8, Att. PMN-LL-2G at 2; Gas Lead-lag Study Workpapers at 4; RR-DPU-20, Att.). Specifically, for 2008 the collection lag was for 35.80 days for the electric division and 47.39 days for the gas division; for 2010, the collection lag was 34.93 days for the electric division and 50.27 days for the gas division (RR-DPU-20, Att.).

The Company states that the effect of Winter Storm 2008 on the gas and electric collection lags for the test year is unknown but that it does not consider any effect to be material (Exhs. DPU-12-2 (electric), DPU-9-2 (gas)). In particular, the Company states that

[86] Fitchburg states that the 14.96 day difference in collection lag between the two divisions is likely caused by the fundamentally different payment cycle arising from the seasonal nature of gas and electric commodities (Exh. DPU-12-4 (electric); Tr. 4, at 399-402). More specifically, the gas division bills the majority of its sales in the five-month winter period when the Company cannot terminate service for non-payment (i.e., during the winter moratorium) (Exh. DPU-12-4 (electric); Tr. 4, at 399-402). This results in a high percentage of non-payment occurring during a period when service cannot be terminated, resulting in a large spike in gas customer payments at the end of the winter as compared to electric customer payments which are spread more evenly through the year (Tr. 4, at 294, 400-402).

while there were some issues with bill payments and estimation of bills related to Winter Storm 2008, overall customer payment habits did not change (Tr. 4, at 406).[87] Nonetheless, we find that the Company has failed to demonstrate that the unusually high collection lags experienced in the test year are not anomalies and are representative of the expected time delay between the issuance of customers' bills and the receipt of billed revenues. See D.P.U. 10-55, at 204.

Despite the Company's assertion that Winter Storm 2008 (which occurred in December 2008) did not have a measureable impact on the collection lags, the electric division's collection lag increased from 35.80 days in 2008 to 37.25 days in 2009 (Exh. Unitil-PMN-2E at 8, Att. PMN-LL-2E at 1; Electric Lead-lag Study Workpapers at 4; RR-DPU-20, Att.). The evidence demonstrates that the Company had an unusually high collection lag during the early months of the test year, immediately following Winter Storm 2008. On a monthly basis, the electric accounts receivable balance increased from $6,736,384 beginning in January 2009 to $8,672,305 by the end of February 2009 (Electric Lead-lag Study Workpapers at 4).[88] Similarly, the gas division's accounts receivable balance increased from $5,620,018 in December 2008 to $9,261,987 in February 2009 (Gas Lead-lag Study

87 In other words, according to the Company, people who paid their bills on a timely basis prior to Winter Storm 2008 continued to do so after the storm (Tr. 4, at 406).

88 Comparing the same period the following year, the electric division's accounts receivable balance increased from $6,029,570 at the start of January 2010 to $6,601,331 by the end of February 2010 (RR-DPU-20, Att. at 3).

Workpapers at 4)[89] The Company itself suggests that 2009 represented the deepest part of the recession and may have skewed the collection lags higher (Tr. 13, at 1751). As the test year collection lags are higher than the lags for 2008 and 2010, both the Company and its lead-lag consultant accept that an average may be a better way to evaluate the future collection lag (Tr. 12, at 1543; Tr. 13, at 1751-1753).

For these reasons, the Department finds that it is necessary to adjust the Company's test year collection lags to reflect a more representative past and future lag. The Department finds that a two-year average of the Company's gas and electric collection lags for 2008 and 2010 is more representative of past and expected future collection lags than the test year and, therefore, appropriate to use for the determination of the cash working capital requirements in this case (Tr. 12, at 1543; Tr. 13, at 1751-1753; RR-DPU-20, Att.). See D.P.U. 10-55, at 204-205.[90] Using a two-year average of the Company's collection lags for 2008 and 2010, the Department approves a collection lag for the electric division of 35.36 days (Exh. DPU-12-5, Att. (electric); RR-DPU-20, Att.). Likewise, using a two-year average of the Company's collection lags for 2008 and 2010, the Department approves a collection lag for the gas division of 48.83 days (Exhs. DPU-9-4, Att. 1 (gas); DPU-RR-20, Att. 1).

89 As a point of comparison, the gas division's accounts receivable balance climbed above $7,000,000 only once during 2008 and not a single time during 2010 (RR-DPU-20, Att. at 2, 4).

90 The Department was unable to review collection lag data for the years prior to 2008 because such data was not available and the Company estimated that the cost of gathering the data would be equal to the cost of running a new lead-lag study (Exh. DPU-12-8 (electric); Tr. 4, at 408-409).

Even with the adjustments discussed above to reduce the Company's collections lags, Fitchburg's collection lag is the primary driver of the high net lag for the gas division and a substantial driver of the high net lag for the electric division (Exhs. Unitil-PMN-2E, Att. at 2; Unitil-PMN-2G, Att. PMN-LL-2G at 2). The collection lag is not only the largest component of the revenue lag but also the component over which the Company has the greatest control, as it is responsible for collecting payment from its customers. As discussed in Section X.B, below, the level of the Company's write-offs and uncollectable expense has increased in recent years (Exhs. DPU-12-4 (electric); AG-3-12, Att. 1 (electric); AG-8-27, Att. 1 (gas); Tr. 4, at 413-419). Although the Company has demonstrated a decline in accounts receivable post-test year, the gas division's 2010 collection lag of 50.27 days is still extremely high (RR-DPU-2G, Att.). See D.P.U. 10-55 at 203-204.

In order to recover cash working capital related to a collection lag, a company must demonstrate that it has taken all reasonable steps to reduce such lag to the extent practicable. The Company has outlined three steps it is taking to reduce its collection lags on a going forward basis: (1) the introduction of an automated system to contact delinquent customers; (2) enhancements to its arrearage management program; and (3) the hiring of a customer assistance program coordinator (Exh. DPU-12-4 (electric)). To evaluate the Company's efforts in this regard, the Department directs the Company to track its monthly accounts receivable balances and yearly collection lags and present the results as part of its cash working capital filing in its next rate case.

iii. Conclusion

The revised electric division collection lag results in a revenue lag of 53.01 days for the electric division (see Exh. DPU-12-5, Att. (electric)).[91] The revised gas division collection lag results in a revenue lag of 66.49 days for the gas division (see Exh. DPU-9-4, Att. 1 (gas)). The Department finds that these revenue lags are appropriate to use for the determination of the Company's cash working capital requirements.

d. Net Lag Factors

As noted above, the difference between the calculated revenue lag and the calculated expense lead is the net lag. The modifications made above to the Company's collection lags result in revised net lag factors. The revised net lag factors are as follows for the electric division: (1) 13.85 days for purchased power; (2) 24.06 days for external transmission, and (3) 31.41 days for O&M expenses. The revised net lag factors are as follows for the gas division: (1) 26.53 days for purchased power; and (2) 44.58 for O&M expense. The adjustments made by the Department to the Company's collection lags reduce the net lag for the gas division's O&M expense from 47.96 days to 44.58 days.

The Department's current standard of review for cash working capital requires gas and electric companies to conduct a lead-lag study where cost effective (i.e., where the normalized cost of the study is less than the reduction in revenue requirement that would occur using the

91 The revenue lags are the sum of the service lags (15.21 days), billing lags (2.49 days) and the respective collection lags (35.36 days for electric and 48.83 days for gas) (see Exhs. Unitil-PMN-2E, Att. PMN-LL-2E at 2; Unitil-PMN-2G, Att. PMN-LL-2G at 2).

results of the lead-lag study in lieu of the 45-day convention). Where such studies would not be cost effective, companies are required to propose a reasonable alternative to develop a lead-lag factor. D.T.E. 03-40, at 92; D.T.E. 02-24/25, at 57; D.T.E. 98-51, at 15.

In its last two litigated rate cases, the Company argued that the cost of running a lead-lag study would not be cost effective given the high cost of the study. D.P.U. 07-71, at 46; D.T.E 02-24/25, at 54,[92] In D.T.E. 02-24/25, at 55-56, the Department was critical of the Company's reasoning, finding that Fitchburg merely "undertook an analysis to prove a premise that the Department has already accepted, namely that lead-lag studies, because of their cost, are unlikely to be cost-beneficial for ratepayers." Rather than deny Fitchburg any cash working capital allowance, the Department reviewed a partial survey of expense lags provided by the Company and made several adjustments that resulted in a lead-lag factor of 37.35 days. D.T.E. 02-24/25, at 56-57. In D.P.U. 07-71, at 48, Fitchburg did not conduct a new lead-lag study or revise the cost-benefit analysis performed in 2002 but chose instead to rely on the results of the Department's lead-lag analysis in D.T.E. 02-24/25. The Department determined that the high cost of a new lead-lag study in 2007 would outweigh whatever benefits might accrue to ratepayers as the result of a possible reduction to the lead-lag factor. D.P.U. 07-71, at 48. Accordingly, the Department applied the results of its lead-lag analysis developed in D.T.E. 02-24/25 to allow a lead-lag factor of 37.35 days in D.P.U. 07-71. D.P.U. 07-71, at 48.

[92] In particular, Fitchburg notes that in 2002, it received two bids to perform the lead-lag studies, one for $193,000 and another for $60,000 (RR-DPU-17).

In the instant proceedings, the Company states that it received a much lower quote to perform a lead-lag studies than it had in previous cases (i.e., $43,210) (RR-DPU-17). It proceeded with the lead-lag studies (RR-DPU-17; see also Company Brief at 42, 44). The Company notes that it was unable to compare the results of a lead-lag study with the 45-day convention to determine if it was actually cost-effective without performing the study (Tr. 4, at 390-391).

In the past several years, lead-lag studies have consistently resulted in savings for ratepayers by reducing the cash working capital requirement below the 45-day convention. See, e.g., D.P.U. 10-114, at 108 (42.22 days); D.P.U. 10-70, at 78 (18.98 days); D.P.U. 10-55, at 204-205 (27.21 days for Boston Gas, and 21.79 days for Colonial Gas); D.P.U. 09-39, at 114 (21.87 days); D.P.U. 09-30, at 151-152 (43.85 days); D.P.U. 08-35, at 38 (21.28 days); D.T.E. 05-27, at 99-100 (42.21 days).[93] Thus, we find that ratepayers stand to benefit from a properly conducted lead-lag study. Further, the costs associated with conducting a lead-lag study have declined, as evidenced by the costs associated with the lead-lag studies performed in the instant cases versus those quoted to the Company in 2002 (RR-DPU-17). Accordingly, we find it appropriate to refine our standard regarding the conduct of lead-lag studies here.

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[93] In instances where companies bill less frequently than monthly (e.g., most water companies), a lead-lag study will likely result in a higher cash working capital requirement than the 45-day convention. Massachusetts-American Water Company, D.P.U. 19900, at 9-11 (1979).

In all future rate proceedings, gas and electric companies serving more than 10,000 customers will be required to conduct a fully developed and reliable O&M lead-lag study. A gas or electric company of such size will no longer will have the discretion to forego conducting a lead-lag study. We fully expect that the results of such lead-lag studies will produce a lead-lag factor well below 45 days. In the event that the lead-lag factor is not below *45* days, companies will bear a heavy burden to justify why the results of such study are reliable and that the company has taken all reasonable steps to minimize all factors affecting cash working capital requirements within its control, such as the collections lag.

5. Conclusion

Application of the electric distribution-related lead-lag factor of 31.41 days to the level of O&M expense authorized by this Order produces a cash working capital allowance of $665,115. Application of the gas distribution-related lead-lag factor of *44.58* days to the level of O&M expense authorized by this Order produces a cash working capital allowance of $902,555. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

IX. REVENUES

A. Weather Normalization

1. Introduction

The Company calculated a weather normalization adjustment to represent the gas sales and revenues that would be expected for the test year under normal weather conditions (Exh. Unitil-PMN-1, at 4 (gas)). Specifically, Fitchburg proposes to decrease test year gas revenues by $56,406 because of colder than normal weather during the test year (Exh. Sch. RevReq-7-1 (Supp. 3) (gas)).[94]

[94] The Company defined normal weather as being equal to the average degree days over the last 20 years (Exh. Unitil-PMN-1, at 4 (gas)).

In calculating the proposed weather normalization adjustment, the Company first calculated the weighted average test year actual and 20-year normal degree days for each billing month, for each rate class (Exh. Unitil-PMN-1, at *5* (gas)). Next, base load gas sales were computed for each rate class as the average use per customer in the months of July and August (Exh. Unitil-PMN-1, at *5* (gas)). The Company did not weather normalize the gas sales for those months where sales fell below the July and August average use as they did not show any sensitivity to weather (Exh. Unitil-PMN-1, at *5* (gas)). To calculate the monthly sensitivity to degree day variation, the Company divided the heating load by the actual billing cycle degree days to derive the actual unit heating load per degree day (Exh. Unitil-PMN-1, at *5* (gas)). The Company then multiplied the actual unit heating load per degree day by the temperature departure from the normal temperature to develop a weather adjustment (Exh. Unitil-PMN- 1, at *5* (gas)). Finally, the Company multiplied the weather sales volume adjustment by the distribution rate in each of the current tariffs and summed the results for all rate classes to derive the proposed revenue adjustment (Exh. Unitil-PMN-1, at 6 (gas)). No party commented on the Company's proposed weather normalization adjustment.

2. Analysis and Findings

The Department's standard for weather normalization of test year revenues is well established. See, e.g., D.P.U. 10-55, at 241-215; D.T.E. 03-40, at 22; D.T.E. 02-24/25, at 75 (2002); D.P.U. 96-50 (Phase I) at 36, 39; D.P.U. 93-60, at 75-80. We find that the method Fitchburg used to weather normalize test year revenues is consistent with this precedent and, therefore, we approve Fitchburg's proposed weather normalization adjustment that reduces the Company's test year revenues by $56,406.

B. Pole Attachment Revenues

1. Introduction

During the test year, the Company received $75,792 in revenues associated with pole attachment fees,[95] which were booked to Account 454 (Rent Electric Property — CATV) (see Exh. AG-1-34, Att. (electric)). Fitchburg revises its pole attachment rates annually, effective May 1 of each year (RR-AG-42). The Company's pole attachment revenues increased in 2010 to $109,490, primarily due to an increase in rates billed per pole and an overall increase in the number of pole attachments (Exhs. AG-1-34, Att. (electric); AG-23-2 (electric); Tr. 15, at 1882-1883).

[95] Pole attachment fees are charged to parties (such as cable television companies) that attach to the Company's distribution poles. See G.L. c. 166, § 25A and 220 C.M.R. § 45.00 et seq.

2. Positions of the Attorney General

The Attorney General asserts that the Company should be required to increase its test year revenues by $33,698 as a result of a known and measurable change in pole attachment revenues (Attorney General Brief at 172-173). In support of her position, the Attorney General contends that the Department's precedent is clear that pole attachment revenues should be credited to a utility's overall cost of service (Attorney General Brief at 172, citing Massachusetts Electric Company, D.P.U. 94-50 (1995)). The Attorney General further argues that the Department has found that such revenues should be adjusted to annualize the most recent pole attachment rates and the most recent number of attachments (Attorney General Brief at 172-173, citing D.T.E. 02-24/25, at 75-76; Commonwealth Gas Company, D.P.U. 87-122, at 12-13 (1987); D.P.U. 85-266-A/85-271-A at 117-118; D.P.U. 1720, at 85). No other party addressed this issue on brief.

3. Analysis and Findings

In determining the propriety of rates for the companies under its jurisdiction, the Department has consistently based allowed rates on test year data, adjusted for known and measurable changes. Eastern Edison Company, D.P.U. 1580, at 13-17 (1984). The selection of an historic twelve-month period of operating data as the basis for setting rates is intended to provide for a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Eastern Edison Company, D.P.U. 1580, at 13-17 (1984). We find that the increase in pole attachment revenues constitutes a known and measurable change to the Company's test year revenues (see Exh. AG-1-34, Att. (electric); Tr. 15, at 1882-1883). Accordingly, the Department will increase Fitchburg's test year revenues by $33,698 to account for the known and measurable post-test year increase in pole attachment revenues.

C. Water Heater and Conversion Burner Rental Programs

1. Introduction

Fitchburg offers a water heater and conversion burner rental program for its gas customers and a water heater rental program for electric customers (collectively referred to as "Rental Programs") (see Exhs. Unitil-MHC-3 (gas); Unitil-MHC-3 (electric); Tr. 17, at 2234). In support of the instant filings, the Company submitted a rental water heater and conversion burner study and a rental water heater study that details the revenues and expenses associated with the Rental Programs (Exhs. Unitil-MHC-3 (gas); Unitil-MHC-3 (electric)).

During the test year, the Company's water heater and conversion burner rental program for its gas customers generated $436,149 in revenues and incurred $90,773 in expenses (Exhs. Unitil-MHC-3, at 1 (gas); Sch. RevReq- 1, at 2 (Supp. 3) (gas)). Of these expenses, the Company reports $56,351 in direct expenses and $34,422 in indirect expenses allocated to the rental program (Exh. Unitil-MHC-3, at 2, 6 (gas)).

During the test year, the Company's water heater rental program for its electric customers generated $56,566 in revenues and incurred $17,760 in expenses (Exhs. Unitil-MHC-3, at 1 (electric); Sch. RevReq- 1, at 2 (Supp. 3) (electric)). Of these expenses, the Company reports $14,484 in direct expenses and $3,276 in indirect expenses allocated to the program (Exh. Unitil-MHC-3, at 1, 6 (electric)).

The direct expenses associated with the Rental Programs include the cost of maintenance of the appliances as well as bad debt expense (Exhs. Unitil-MHC-3, at 6 (gas); Unitil-MHC-3, at 6 (electric)). The indirect costs assigned to the Rental Programs are primarily costs associated with payroll and benefits, customer service and relations, insurance, and plant maintenance (Exhs. Unitil-MHC-3, at 1, 2 (gas); Unitil-MHC-3, at 1, 2 (electric)). In assigning indirect costs to the Rental Programs, the Company uses an allocator based on a percentage of total revenues from each rental program to total Company revenues (Exhs. Unitil-MHC-3, at 2 (gas); Unitil-MHC-3, at 2 (electric); Tr. 17, at 2233).[96]

Because the Company operates the Rental Programs below-the-line, it has removed from its electric and gas divisions' revenue requirements all of the revenues, expenses, and plant associated with the Rental Programs (Exhs. Unitil-MHC-1, at 12-13 (gas); Unitil-MHC- 1, at 15 (electric)). No party addressed the Company's Rental Programs on brief.

2. Analysis and Findings

The Company has placed the Rental Programs below-the-line for its gas and electric divisions by removing both the related revenues and expenses from its cost of service. Such treatment is consistent with Department precedent. See D.T.E. 02-24/25, at 198; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 78 (1983). However, we conclude that the Company's practice of allocating indirect costs to the Rental Programs based on a percentage of total revenues from each program to total Company revenues may lead to an under-allocation of costs to the Rental Programs.[97]

[96] Property insurance expense is allocated based on the value of plant (Exhs. Unitil-MHC-3, at 2 (gas); Unitil-MHC-3, at 2 (electric)).

[97] For example, under the Company's original proposal the "employee pension and benefits" related costs allocated to the Rental Programs total $18,132 (Exhs. Unitil-MHC-3, at 2 (gas); Unitil-MHC-3, at 2 (electric)). However, when allocated based on the Company's cost of service for each account associated with the Rental Programs, the costs assigned to the Rental Programs increase to $101,364 (RR-DPU-30, Atts. 3, 4).

During the proceedings in this case, the Department developed an evidentiary record regarding alternate methods for the allocation of indirect costs. In particular, the Company provided data supporting a revised allocation method based on the number of customers for each rental program as well as a revised allocation method based on the Company's cost of service for each account associated with the Rental Programs (RR-DPU-30).[98] In both cases, the revised allocation methods result in a substantial increase in the amount of indirect costs allocated to the Rental Programs.[99]

According to Fitchburg, both alternative allocation methods are problematic. The Company contends that the allocation of indirect costs based on the number of customers is

[98] The Company has allocated a portion of the test year expenses to the Rental Programs for each of the following accounts: Accounts 901, 903, 907, 908, 920, 921, 924, *925*, 926, 928, 930, and 935 (See Exhs. Unitil-MHC-3 (gas); Unitil-MHC-3 (electric)).

[99] The indirect costs for the water heater and conversion burner rental program for gas customers increase from $34,422 to (1) $359,941, based on a number of customers allocation method, and (2) $183,440, based on a cost of service allocation method (RR-DPU-30, Atts. 1, 3). The indirect costs for the water heater rental program for electric customers increase from $3,276 to (1) $33,681, based on a number of customers allocation method, and (2) $23,904 based on a cost of service allocation method (RR-DPU-30, Atts. 2, 4).

flawed because (1) these costs are not driven by the number of customers; and (2) this allocation method improperly equates a rental customer to an electric or gas customer (Tr. 17, at 2243). The Company asserts that an allocation of indirect costs based on the cost of service of each account associated with the Rental Programs may lead to an over-allocation of indirect costs because of the small size of the Rental Programs (Tr. 17, at 2243). However, the Company concedes that, because such an allocation is based on cost causation factors, it would be more difficult to question the appropriateness of this method (Tr. 17, at 2244).

For the reasons discussed above, we conclude that the Company's revenue requirement needs further adjustment to reflect a more representative amount of indirect costs associated with the Rental Programs. We find that an allocation method based on the cost of service by account is a more appropriate method of determining indirect costs to be assigned to the Rental Programs. This allocation method does not rely on a single allocator (i.e., revenue) to allocate all costs, but instead it properly functionalizes and classifies the Rental Programs' costs in the same manner as the Company's cost of service study. Thus, assigning a portion of costs from each of these accounts to the Rental Programs yields a more representative amount of indirect costs that will be allocated to each program.

Applying an allocation method based on the cost of service by Account, the Department will reduce the Company's proposed cost of service for its electric division by $20,628, and reduce the proposed cost of service for its gas division by $149,018, for a combined reduction of $169,646. We direct the Company to incorporate into future rental water heater and conversion burner and a rental water heater studies a method of allocating indirect costs that is based on the cost of service of each account associated with the Rental Programs.

D. Special Contracts

As discussed above in Section VI.E.3.f the Department directs the Company to remove the test year revenues billed to the post-test year special contract gas customer and credit them to the revenue requirement for its gas division. In addition, the Company shall remove the test year billing data for the post-test year special contract gas customer for the purpose of calculating base rates.

X. OPERATIONS AND MAINTENANCE EXPENSES

A. Employee Compensation

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach recognizes that the different components of compensation (e.g., wages and benefits) are to some extent substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55.

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

Fitchburg's employee compensation program includes base pay, incentive compensation, vacation and holiday pay, medical and dental insurance, life insurance, disability insurance, and matching contributions to a 401(k) savings plan, and a pension and post retirement benefits other than pension plan ("Pension/PBOP") (Exhs. AG-1-42, Att. 1 (electric); AG-1-50 (electric); AG-6-5, Atts. 1-3 (electric); AG-5-5 (gas)).

2. Payroll Expense

During the test year, Fitchburg booked to its electric division $2,921,473 in payroll expense, consisting of $1,130,034 of direct Fitchburg labor and $1,791,439 which was allocated from USC (Exh. Sch. RevReq-7-1 (Supp. 3) (electric)). During the test year, Fitchburg booked to its gas division $3,096,943 in payroll expense, consisting of $1,556,575 of direct Fitchburg labor and $1,540,368 which was allocated from USC (Exh. Sch. RevReq-7-3 (Supp. 3) (gas)).

a. Union Wage Increase

i. Introduction

During the test year, Fitchburg booked $730,347 in union payroll expense to its electric division and $1,020,050 to its gas division (Exhs. RevReq-7-1 (Supp. 3) (electric); RevReq-7-3 (Supp. 3) (gas)). The Company proposes to increase union payroll expense by $53,487 for its electric division and by $74,452 for its gas division (Exhs. Sch. RevReq-7-3 (Supp. 3) (electric); WP-3-1.3, at 2 (Supp. 3) (electric); Sch. RevReq-7-3 (Supp. 3) (gas)). The proposed adjustments to the test year expense account for a three percent pay raise that took effect on June 1, 2009, a three percent pay raise that took effect on June 1, 2010, and a three percent pay raise that took effect on June 1, 2011, in accordance with union contracts (Exhs. Sch. RevReq-7-3 (Supp. 3) (electric); Sch. RevReq-7-3 (Supp. 3) (gas); AG-1-42, Att. 2, at 1 (electric)).

ii. 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 date of the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 73-74 (1987).

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (i.e., through February 1, 2012) (Exhs. AG- 1-42, Atts. 1, 2 (electric); AG- 1-42 (gas)). Further, because the union payroll increases are based on signed collective bargaining agreements, the Department finds that the proposed increases are known and measurable (Exhs. AG-1-42, Att. 2 (electric); AG-1-42 (gas)). Finally, the Company provided a 2009 wage survey of New England distribution utilities, demonstrating that the wages paid to union employees are reasonable (Exhs. AG-6-8, Att. 1 (electric); AG-5-8 (gas)). Accordingly, the Department will increase Fitchburg's test year cost of service by $53,487 for the electric division and $74,452 for the gas division to account for a known and measurable change to test year payroll expense.

b. Non-Union Wage Increases

i. Introduction

During the test year, Fitchburg booked $2,191,126 in non-union payroll expense to its electric division (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); Sch. RevReq-7-3 (Supp. 3) (gas)). Of this amount, Fitchburg booked $399,687[100] in direct wages and salaries and incentive compensation, and $1,791,439, which was allocated from USC (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); WP-7-1 .1 (Supp. 3) (electric)).

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[100] For the electric division, the amount of $399,687 in direct O&M payroll expense attributable to non-union labor is derived by reducing the test year direct payroll amount of $1,130,034 by the test year union payroll amount of $730,347 (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); WP-7-1.1 (Supp. 3) (electric)). The amount of $399,687 consists of $369,609 in direct wages and salaries and $30,078 in incentive compensation (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); WP-7-1.1 (Supp. 3) (electric)).

During the test year, Fitchburg booked $2,076,893 in non-union payroll expense to its gas division (Exhs. Sch. RevReq-7-1 (Supp. 3) (gas); Sch. RevReq-7-3 (Supp. 3) (gas)). Of this amount, Fitchburg booked $536,525[101] in direct wages and salaries and incentive compensation, and $1,540,368, which was allocated from USC (Exhs. RevReq-7-3 (Supp. 3) (gas); WP-7-3.2 (gas)).

The Company proposes an increase to non-union payroll expense of $103,278 for the electric division and $107,645 for the gas division (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); Sch. RevReq-7-3 (Supp. 3) (gas)). The proposed adjustments are derived by increasing test year payroll expense based on actual direct compensation expense and target incentive compensation expense (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric); Sch. RevReq-7-3 (Supp. 3) (gas); AG- 3-6 (electric)).[102] The Company adjusted the test year payroll expense by two percent for a non-union salary increase that took effect on January 1, 2010, and by three percent for a non-union salary increase that took effect on January 1, 2011

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101 For the gas division, the amount of $536,525 in direct O&M payroll expense attributable to non-union labor is derived by reducing the test year direct payroll amount of $1,556,575 by the test year union payroll amount of $1,020,050 (Exhs. Sch. RevReq-7-3 (Supp. 3) (gas); WP-7-3.2 (Supp. 3) (gas)). The amount of $536,525 consists of $516,221 in direct wages and salaries and $20,304 in incentive compensation (Exhs. Sch. RevReq-7-3 (Supp. 3) (gas); WP-7-3.2 (Supp. 3) (gas)).

102 The target incentive for the Incentive Plan available to non-union employees is five percent of base pay, while the target incentive under the Management Plan is determined by pay level. See Section X.A.3, below.

(Exhs. Unitil-GEL- 1, at 5 (electric); Sch. RevReq-7- 1 (Supp. 3) (electric); Unitil-GEL- 1, at 5 (gas); Sch. RevReq-7-3 (Supp. 3) (gas)). The wage increases were determined based on surveys of market competitiveness and the recommendations of employee compensation consultants (Exhs. Unitil-GEL- 1, at 7 (electric); Unitil-GEL- 1, at 6-7 (gas); Tr. 4, at 325). Fitchburg made no adjustments to payroll expense for staffing levels (Exhs. Sch. RevReq-7-1 (Supp. 3) (electric)); Sch. RevReq-7-3 (Supp. 3) (gas)).

ii. Analysis and Findings

The Department's standard for post-test year non-union wage increases requires a company to demonstrate that: (1) the non-union salary increases are scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, that there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. D.P.U. 85-266-A/271-A at 107; D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

Here, the Company is not proposing to include any post-Order wage increases. The Company's proposed non-union payroll adjustments include only those increases that have been granted through the date of this Order (Exhs. RevReq-7-1 (Supp. 3) (electric); RevReq-7-3 (Supp. 3) (gas)).

Further, we find that the Company has demonstrated a sufficient historical correlation between the union and non-union raises (Exhs. AG-1-41 (electric); AG-1-41 (gas)).

Specifically, between 2004 and 2010, annual union wage increases were between three and four percent and non-union increases were between two and 4.76 percent (Exhs. AG-1-41 (electric); AG-1-41 (gas)). The coefficient of correlation between union and non-union wage increases for the period 2004 to 2010 was 0.82, demonstrating a high level of correlation between the two groups (Exhs. AG-1-41 (electric); AG-1-41 (gas)). Therefore, the Department finds that a sufficient correlation exists between union and non-union wage increases. See D.P.U. 07-71, at 76; Essex County Gas Company, D.P.U. 87-59-A at 18 (1988).

Finally, with respect to the reasonableness of the non-union wage increase, the Company's policy is to compensate employees at the median of the marketplace for base pay and total cash compensation (Exhs. Unitil-GEL- 1, at 6 (electric); Unitil-GEL- 1, at 6 (gas)). USC developed a review of non-union compensation in collaboration with an employee compensation consultant (Exhs. Until-GEL-1, at 6 (electric); Unitil-GEL-1, at 6 (gas); AG-6-5, Att. 1 (electric); AG-5-5 (gas)). The study found that the average test year base salaries were 96 percent of the market median (Exhs. AG-6-5, Att. 1, at 7 (electric); AG-5-5 (gas)). Test year total target cash compensation was 95 percent of the market median (Exhs. AG-6-5, Att. 1, at 7 (electric); AG-5-5 (gas)). The Department finds that the market compensation data presented by Fitchburg are sufficient to confirm the reasonableness of the Company's non-union salary levels. See D.P.U. 10-55, at 245; D.P.U. O5-27, at 109; D.T.E. 02-24/25, at 94.

Based on the above, we find that Fitchburg has demonstrated that: (1) the non-union salary increase already has been granted; (2) there is a historical correlation between union and non-union payroll increases; and (3) the increase is reasonable. Accordingly, we allow the Company's non-union payroll expense adjustments for its electric and gas divisions.

c. Executive Officer Compensation

i. Introduction

The executive officers of Unitil also act as executives for Fitchburg and, therefore, allocate a portion of their overall compensation costs to the Company (Tr. 13, at 1595-1596). In 2009, USC, on behalf of Unitil's subsidiaries, developed a compensation study ("Compensation Study") with support from a compensation consultant (Exhs. Unitil-GEL-1, at 6 (electric); Unitil-GEL-1, at 6 (gas)). The Compensation Study reviewed the competitiveness of market pay based upon a peer group of 19 energy service organizations as well as a subset of 14 organizations with sales of approximately one-half to two times those of Unitil (Exhs. AG-6-5, Att. 2, at 3, 8 (electric); AG-5-5 (gas)).[103]

The executive compensation was directly billed by USC to Fitchburg (Exhs. AG-1-28, Att. 3 (electric); AG-1-28 (gas); Tr. 13, at 1590-1592, 1602, 1604). The amount billed to Fitchburg is approximately 28.78 percent of Unitil's executive compensation costs, and is further allocated among the Company's operating divisions as follows: 59.7 percent to the electric division and 40.3 percent to the gas division (Exhs. AG-1-28, Att. 3; AG-21-3, Att. 1, at 1 (electric); AG-5-5 (gas)).

103 Test year sales for Unitil were approximately $400 million, compared to a median of the 19-company peer group of $960 million and a median of the 14-company subset peer group of $875 million (Exhs. AG-6-5, Att. 2, at 9-10 (electric); AG-5-5 (gas)).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the compensation for Fitchburg's chief executive officer ("CEO") and chief financial officer ("CFO") is well in excess of the compensation of like officers at utilities of similar size (Attorney General Brief at *50;* Attorney General Reply Brief at 18). The Attorney General cites to the Compensation Study to support her position (Attorney General Brief at *50;* Attorney General Reply Brief at 18-19). Specifically, the Attorney General argues that the study consultant selected a comparison group of utility companies and ultimately recommended using the lowest 25th percentile of the group (i.e., the smallest in terms of revenues) as the benchmark against which to evaluate the CFO and CEO salaries (Attorney General Brief at 50, citing Exh. AG-6-5, Att. 2, at 8). The Attorney General contends that, based upon the salary information contained in the Compensation Study for companies in the lowest 25th percentile of the proxy group, Fitchburg's CEO and CFO are overpaid (Attorney General Brief at 50-51; Attorney General Reply Brief at 20). According to the Attorney General, the Company has not demonstrated that these officers are worthy of the higher levels of compensation at which they are paid (Attorney General Brief at 51). Accordingly, the Attorney General asserts that the Company's cost of service should be reduced so that Fitchburg's executive compensation is below the level of the 25th percentile of the proxy group (Attorney General Brief at 51; Attorney General Reply Brief at 20, citing D.T.E. 02-24/25, at 92-95; D.P.U. 92-250, at 55-56; D.P.U. 93-60, at 130-131).

(B) Fitchburg

The Company argues that based, upon the recommendations contained in the Compensation Study, it is appropriate to compare the salaries of Unitil executives with executives from companies that rank between the lowest 25th percentile and the median of peer utilities (Company Brief at 63, citing Exh. AG-6-5, Att. 2, at 8 (confidential) (electric); Company Reply Brief at 29). Further, the Company contends that it is more appropriate to compare target levels of compensation rather than actual compensation because actual compensation varies considerably from year to year (Company Reply Brief at 29).

According to the Company, a comparison of its CEO's target compensation to executives of utilities in the 25th percentile peer group demonstrates that the Company's CEO earns only two percent more than comparable executives (Company Reply Brief at 29, citing Exhs. AG-6-5, Att. 2, at 11 (confidential) (electric); AG-5-5 (gas)). Therefore, the Company asserts that its CEO is paid at the level of the 25th percentile (Company Reply Brief at 29). Regarding its CFO, the Company argues that a comparison of target level compensation demonstrates that the CFO is paid below the 25th percentile (Company Reply Brief at 29, citing Exhs. AG-6-5, Att. 2, at 16 (confidential) (electric); AG-5-5 (gas)).

Finally, the Company argues that the direct compensation levels that are reflected in the cost of service (i.e., base salary, targeted annual incentive and target long term incentive) are significantly lower than the compensation levels used in the Compensation Study and cited by the Attorney General (Company Reply Brief at 30). The Company attributes this difference to two factors: (1) the fact that shares of restricted stock are not expensed and, therefore, not booked to incentive compensation until they vest; and (2) the fact that the Compensation Study considered Fitchburg's 2008 incentive compensation level, which was at 133 percent of the target payout and, once adjusted to incorporate 100 percent of the target payout, would reduce the direct compensation for its CEO and CFO (Company Reply Brief at 30).

The Company submits that the Compensation Study demonstrates that the total compensation of its CEO and CFO are reasonable based on Unitil's size (Company Brief at 63, citing Exhs. AG- 6-5, Att. 2, at 8, 24-25 (confidential) (electric); AG-5-5 (gas)). Further, Fitchburg notes that Unitil's CEO and CFO also serve in the same capacities for Fitchburg and thus allocate approximately 28.8 percent of their compensation to Fitchburg (Company Brief at 63; Tr. 13, at 1608-1609). Accordingly, the Company claims that the allocated portion of the compensation of the CEO and CFO paid by Fitchburg also is reasonable (Company Brief at 63-64).[104]

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[104] The Company allocates $172,796 and $68,744 of CEO and CFO compensation respectively to Fitchburg's electric division. The Company allocates $116,644 and $46,456 of CEO and CFO compensation respectively to Fitchburg's gas division (Exhs. AG 6-5, Att. 2, at 24-25 (electric) (confidential); AG-1-28, Att. 3, at 1 (electric); AG-1-28 (gas); Tr. 13, at 1608-1609).

iii. Analysis and Findings

The Compensation Study considered Unitil in the context of a 19-company peer group and a smaller subset of 14 companies with comparable sales (Exhs. AG-6-5, Att. 2, at 3, 8 (electric); AG-5-5 (gas)).[105] For the purpose of our comparative analysis here, the Department finds that it is appropriate to more heavily weigh the 14-company subset, as the companies included in this peer group closely resemble Unitil in terms of sales (Exhs. AG-6-5, Att. 2, at 10 (electric); AG-5-5 (gas)).

The Attorney General argues that Unitil's executives, specifically the CEO and CFO, are over-compensated (Attorney General Brief at 50-51; Attorney General Reply Brief at 20). Based on the size of the Company, the Attorney General recommends that the Department should reduce the executive compensation included in Fitchburg's cost of service to below the level of the total direct compensation at the 25th percentile in the Compensation Study (Attorney General Brief at 50; Attorney General Reply Brief at 20). The Company counters that its compensation consultant recommends that it is appropriate to compensate Fitchburg's executives in the range between the 25th percentile and the median of the companies in the comparison group (Company Brief at 63; Company Reply Brief at 29).

Evaluating relative size by sales, the 25th percentile for the 14-company peer group in the Compensation Study is $537.6 million and the median is $874.9, compared to $400 million for Unitil (Exhs. AG-6-5, Att. 2, at 10 (electric); AG-5-5 (gas)). Evaluating relative size by

[105] Sales in the range of half to two times Unitil's sales were considered comparable (Exhs. AG-6-5, Att. 2, at 8 (electric); AG-5-5 (gas)).

the number of employees, the 25th percentile for the 14-company peer group in the Compensation Study is 562 employees and the median is 867 employees, compared to 406 employees for Unitil (Exhs. AG-6-5, Att. 2, at 9-10 (electric); AG-5-5 (gas)). Based on these data, the Department finds that the 25th percentile of the peer group in the Compensation Study is a more appropriate benchmark for Unitil's executive compensation than the median (Exhs. AG-6-5, Att. 2, at 10 (electric); AG-5-5 (gas)).

The Attorney General's objections to Fitchburg's executive compensation are based on her evaluation of the compensation of Unitil's CEO and CFO. However, in order to evaluate the reasonableness of the Company's executive compensation, we find that it is necessary to review a broader range of the Company's executives. The Compensation Study provides data on the top five executives in the 14-company peer group. The Department finds that an analysis of the compensation of the top five executives at Unitil as compared to the peer group is an appropriate benchmark of whether Unitil's total executive compensation is reasonable.

As compared to the total compensation for the top five executives in each company in the peer group, Unitil paid its top five executives only slightly more than the 25th percentile in the test year — $2,373,000 as compared to $2,303,000 for the 14-company peer group (Exhs. AG-6-5, Att. 2, at 28 (electric); AG-5-5 (gas)).[106] Although the total compensation of

[106] Moreover, the Compensation Study is based on 2008 data (Exhs. AG-6-5, Att. 2, at 28 (electric); AG-5-5 (gas)). It is reasonable to assume that the salaries for the peer group were higher in 2009 than they were in 2008.

Unitil's CEO and CFO is higher in relation to the 14-company peer group at the 25th percentile, the overall compensation levels paid to the top five Company employees does not support a finding of excessive executive compensation. Further, as detailed below, the Department has made a number of adjustments to the Company's allowed incentive compensation, which brings Fitchburg's overall executive compensation for its CEO and CFO more into line with the compensation paid by other companies in the 14-company peer group. For these reasons, the Department finds that Unitil's overall executive compensation is reasonable.

In Section XJ.1, below, the Department approves the allocation formulas used to apportion costs between the Company and the rest of Unitil's operations. Based on these factors and the findings above, the Department concludes that the overall level of executive compensation allocated to Fitchburg is reasonable.

3. Incentive Compensation

a. Introduction

The Company offers two incentive compensation programs. The first, the Unitil Corporation Incentive Plan ("Incentive Plan"), is open to all employees of Unitil except: (1) those named by the board of directors to participate in the Management Plan; and (2) union members, unless participation is allowed under the terms of a collective bargaining agreement (Exhs. AG 6 17, Att. 1, at 1 (electric); AG-5-17 (gas)). The second program is the Unitil Corporation Management Incentive Plan ("Management Plan"), for which key management employees as selected by Unitil Corporation's board of directors are eligible to participate (Exhs. AG-1-35 (electric); AG-6-17, Atts. 1, 2, 3, 6 (electric); AG-5-17 (gas)).[107]

b. Incentive Compensation Programs

i. Incentive Plan

(A) Introduction

Under the Incentive Plan, employees of Unitil Corporation and its subsidiaries, including the Company, are eligible for an annual target incentive award equal to five percent of their base salaries (Exhs. AG-6-17, Att. 1, at 1 (electric); AG-5-17 (gas); Tr. 10, at 1230-1231). Prior to or soon after the start of each calendar year, a compensation committee establishes performance objectives and weightings for the upcoming year based upon recommendations made by Unitil Corporation's CEO (Exhs. AG-6-17, Atts. 1, 5 (electric); AG-5-17 (gas)). In 2009 and 2010, these performance goals included: (1) earnings per share; (2) three-year average ROE as measured against certain Northeast peer companies; (3) gas safety (i.e., response rate to odor calls); (4) electric reliability (i.e., SAIDI minutes);[108] (5) customer satisfaction; and (6) gas and electric residential distribution rates as measured against certain Northeast peer companies (Exhs. AG-6-17, Att. 5, at 8 (electric); AG-5-17 (gas); RR-AG-11; RR-AG-12). These performance objectives are evaluated based upon three

[107] The Company also offers the Unitil Corporation Restricted Stock Incentive Plan for which all employees, directors, and consultants of Unitil Corporation and its affiliates are eligible to participate (Exhs. AG-1-35 (electric); AG-6-17, Atts. 1, 2, 3, 6 (electric); AG-5-17 (gas)).

[108] SAIDI measures the duration of electric service outages. D.T.E. 99-84, at 22-24.

levels of achievement upon which different payout levels are established: (1) a threshold level for which 50 percent of the target payout (i.e., 2.5 percent of an employee's base salary) is made;[109] (2) a target level for which 100 percent payout (i.e., five percent of an employee's base salary) is made; and (3) a maximum level for which 150 percent of the target incentive payment (i.e., 7.5 percent of an employee's base salary) is made (Exhs. AG-6-17, Att. 1, at 2 (electric); AG-5-17 (gas)). In addition to these quantitative measures, in 2010 a qualitative measure was added whereby the compensation committee can increase or decrease the results of the total quantitative measures based on unplanned events, unforeseen problems, or unique circumstances (RR-AG-10, Att. 1).

At the same time the compensation committee establishes performance goals for the upcoming year, the committee also examines performance over the previous year to determine the appropriate incentive plan payouts to be made (Exhs. AG-6-17, Att. 5 (electric); AG-5-17 (gas); Tr. 10, at 1234-1235). During the test year, the Company determined that based on its 2008 performance measures, it achieved maximum results for four of the six performance measures, resulting in a weighted average performance of 133 percent of target.[110] This determination resulted in a total Incentive Plan award equal to 6.65 percent of an eligible employee's base salary for 2009 (Exh. AG-6-17, Att. 5, at 4-5 (electric); AG-5-17 (gas)). In

[109] No incentive award associated with a performance measure is made if the threshold level for that performance measure is not met (Exhs. AG-6-17, Att. 1, at 2 (electric); AG-5-17 (gas)).

[110] Incentive compensation payments made during the test year were calculated based on performance during 2008 (Exhs. AG-6-17, Att. 5, at 4 (electric); AG-5-17 (gas)).

contrast, the Company determined the following year that it had failed to meet its 2009 earnings per share and customer satisfaction thresholds, but achieved the maximum targets for its gas safety and residential distribution rates performance measures (Exh. AG-6-17, Att. 5, at 7-8 (electric); AG-5-17 (gas)). As a result of this determination, a total Incentive Plan award equal to 4.3 percent of an eligible employee's base salary was paid in 2010 (Exhs. AG-6-17, Att. 5, at 7 (electric); AG-5-17 (gas)).

(B) Positions of the Parties

(1) Attorney General

The Attorney General argues that the design of the Company's Incentive Plan is flawed and, therefore, the associated expenses should be removed in their entirety from the Company's cost of service (Attorney General Brief at 42-43; Attorney General Reply Brief at 17). Specifically, the Attorney General contends that the plan is not structured to benefit ratepayers or to ensure good employee performance (Attorney General Reply Brief at 16-17). Rather, the Attorney General claims that the Company's Incentive Plan, which pays a bonus for the achievement of earnings targets, effectively requires customers to reward the Company's management on a contingency basis for having to pay higher rates (Attorney General Brief at 43).

The Attorney General argues that to the extent that the Company seeks to include the attainment of financial metrics as a direct component of an incentive compensation award, the Department requires a demonstration that the attainment of these goals provides a direct benefit to ratepayers (Attorney General Brief at 45, citing D.P.U. 10-55, at 254). In this regard, the Attorney General contends that the Company failed to quantify direct ratepayer benefits (Attorney General Brief at 45-46; Attorney General Reply Brief at 16).

Although the Attorney General acknowledges that the remaining performance metrics (i.e., gas safety, electric reliability, customer satisfaction, and distribution rates) are more directly related to ratepayer benefits, she argues that they also should be excluded from cost of service because they are based on data for Unitil as a whole rather than data specific to Fitchburg (Attorney General Brief at 47, citing Exh. AG-6-17, Att. 5, at 6 (electric); RR-AG-11; RR-AG-15, Att. 1). More specifically, the Attorney General claims that the Company has failed to demonstrate that incentive compensation plans that combine data from Unitil's Maine, Massachusetts, and New Hampshire operating subsidiaries are reasonably designed to encourage good employee performance for Fitchburg's employees (Attorney General Brief at 47; Attorney General Reply Brief at 16-17). Accordingly, the Attorney General argues that the Department should disallow all incentive compensation costs and require the Company to design a Fitchburg-specific incentive program for future use (Attorney General Brief at 48).

Finally, the Attorney General argues that, should the Department allow the Company to include incentive compensation expense in its cost of service, the Department should disallow the Company's pro-forma adjustment to target level payouts (Attorney General Brief at 48-49; Attorney General Reply Brief at 17). The Attorney General asserts that the Company has failed to support its assertion that the target level of incentive compensation is more representative of future payouts under the Incentive Plan than actual test year expense (Attorney General Brief at 49, Attorney General Reply Brief at 17).

(2) Fitchburg

The Company argues that its Incentive Plan is both reasonable in amount and reasonably designed to encourage good employee performance (Company Brief at 60-61). In support of its position, the Company refers to the results of its Compensation Study which it argues shows that Fitchburg's employees are compensated (including incentive payouts) consistent with median pay levels in New England. Further, the Company argues that like Fitchburg, the average target incentive compensation for non-management employees at companies in the proxy group used in the Compensation Study is five percent of base pay (Company Brief at 60, citing Tr. 4, at 327).

As to whether the incentive compensation plan encourages good employee performance, the Company argues that its performance measures include not only earnings per share and ROE metrics, but also gas safety, electric reliability customer satisfaction, and the overall level of residential distribution rates (Company Brief at 61, citing Exh. AG-6-17, Att. 5 (electric)). The Company asserts that it follows a balanced approach for awarding incentive compensation based on performance measures that are directed towards both benefits for ratepayers and Company finances (Company Brief at 61, citing Tr. 4, at 329). Further, Fitchburg argues that it developed individual employee goals consistent with these Company performance measures to encourage good employee performance (Company Brief at 61, citing Tr. 4, at 330-331).

In response to the Attorney General's criticism that its incentive compensation plan inappropriately includes financial performance measures, the Company argues that the financial performance measures are integrated components of the overall Incentive Plan and, therefore, are consistent with plans previously approved by the Department (Company Brief at 61-62, citing D.P.U. 07-71, at 83-84; Company Reply Brief at 26, citing D.P.U. 10-114, at 144; D.P.U. 10-70, at 104-105). Further, the Company notes that in 2010, incentive compensation was awarded for the achievement of customer service goals despite earnings per share below the threshold (Company Reply Brief at 26, citing RR-AG-10, Att.). In addition, Fitchburg submits that approximately two-thirds of its credit rating, which determines the Company's financing costs and, therefore, affects operating costs, is directly related to earnings per share and ROE (Company Reply Brief at 27). The Company claims that achievement of these financial goals delays the need for subsequent rate cases, and therefore, provides a direct benefit to ratepayers (Company Reply Brief at 27).

Finally, the Company argues that using the target level of incentive compensation payout as a normalized level of costs to include in rates is appropriate because it is representative of the expected payout over time (Company Brief at 62-63; Company Reply Brief at 28).[111] According to the Company, the use of a target level payout eliminates out of period costs incurred during the test year and normalizes the actual payout for 2009 (Company Reply Brief at 28).

[111] The Company notes that the test year incentive compensation was recorded on an accrual basis and reflects estimates for the 2009 payouts as well as a true-up of the 2008 payouts (Company Brief at 62; Company Reply Brief at 28).

(C) Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if they are: (1) reasonable in amount; and (2) the incentive plans are reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

The Department must first determine whether Fitchburg's Incentive Plan is reasonable in design. The Attorney General argues that Fitchburg's incentive compensation structure inappropriately includes performance metrics based on the achievement of financial targets (Attorney General Brief at 43). A portion of the Company's Incentive Plan is tied to meeting financial performance objectives, such as earnings per share and ROE (Exhs. AG-6-17, Att. 5 (electric); AG-5-17 (gas); RR-AG-10, Att.). Fitchburg's earnings per share and ROE performance measures do not operate as threshold components but rather are components in the overall incentive compensation design (Exhs. AG-6-17, Att. 5 (electric); AG-5-17 (gas); RR-AG-10, Att.).

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

While Fitchburg argues that its financial metrics are but one component of its overall Incentive Plan and that the Department has previously accepted the use of such metrics, the Company has provided insufficient evidence that the achievement of the earnings per share and ROE measures will result in direct ratepayer benefits.[112] D.P.U. 10-55, at 254. It is clear that the attainment of these financial targets has a primary and direct shareholder benefit. The Department finds that Fitchburg has failed to demonstrate that the financial components of its performance measures are reasonably designed to encourage good employee performance and result in benefits to the Company's ratepayers. Accordingly, we will exclude that portion of the Company's Incentive Plan expense attributable to the earnings per share and ROE measures.[113]

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112 Even accepting the Company's argument that achievement of these financial goals may delay the need for a subsequent rate case, we find that this is not a showing of direct ratepayer benefit sufficient to permit the inclusion of these costs in rates (see Company Reply Brief at 27).

113 The Company claims that its Incentive Plan is identical in design to the program approved by the Department in its most recent electric rate case in 2007, and that similar plans were recently approved for both WMECo and NEGC. However, Fitchburg's argument ignores the fact that the Department declined to impose the new D.P.U. 10-55 standard on WMECo because the Department issued its Order in D.P.U. 10-55 after the close of the evidentiary record in WMECo's rate case. D.P.U. 10-70, at 105. Moreover, in D.P.U. 10-114, at 144-145, the Department excluded NEGC's corporate management incentive compensation in its entirety from cost of service because that company failed to provide sufficient information on specific employee performance goals, relied exclusively on an earnings per share metric, and failed to include operational or customer service metrics in its plan. The incentive compensation program applicable to direct NEGC employees that the Department approved relied on financial performance standards as threshold measures only. D.P.U. 10-114, at 141-145.

The remaining performance measures include objectives related to safety, reliability, and customer satisfaction (RR-AG-10, Att.). We have found that these types of performance measures are appropriate as they are directly aligned with the interests of ratepayers. D.P.U. 10-70, at 104. While the Attorney General criticizes the Company for relying on system-wide performance measures, in view of the fact that USC's employees provide services to multiple affiliates in multiple states, we find that system-wide performance measures are an efficient way to evaluate performance. Therefore, the Department accepts the use of system-wide performance measures here. However, we recognize that where employees' duties are limited to a single state, system-wide performance metrics could allow these employees to receive an incentive award despite substandard performance in their own service area, merely on the strength of overall system performance. Our clear preference is for Company-specific performance metrics. Accordingly, the Company is directed to examine the feasibility of implementing Fitchburg-specific performance measures for its incentive compensation programs, and to present its conclusions as part of its next rate case. If the Company wishes to maintain system-wide performance metrics, it must demonstrate how such metrics provide a direct benefit to Fitchburg's ratepayers. [114]

With the exception of the financial performance measures discussed above, we find that Fitchburg's Incentive Plan is reasonably designed to encourage good employee performance and provide benefits to ratepayers.

With respect to the issue of whether the Company's Incentive Plan expenses are reasonable, the results of the Compensation Study indicate that the Company's incentive compensation target levels are at or below the market median (Exh. AG-6-5, Att. 1, at 11 (electric)). The Company has achieved its stated objective of being at or below the market median compensation level for the incentive component of compensation both in isolation and in conjunction with the overall compensation package (Exh. AG-6-5, Atts. 1, 2). Therefore, the Department finds that the costs associated with the Incentive Plan are reasonable.

Concerning the level of incentive compensation expense to include in rates, the Attorney General contends that the target amounts associated with the Incentive Plan are not

[114] There is insufficient information in this record to develop Fitchburg-specific performance metrics and identify those Company employees who would be subject to these revised performance metrics.

appropriate for establishing base rates because the Company failed to demonstrate that they provide a better representation of future incentive compensation expenses than actual payouts associated with the Incentive Plan (Attorney General Brief at 49). On the other hand, the Company argues that its proposal is consistent with the principles of basic accrual accounting (Company Brief at 62). While accrual accounting is integral to the ratemaking process, when actual expenses are known and can be easily used to adjust for estimation errors in the accrual process, the Department will adjust booked test year expenses to match the actual expense incurred. D.P.U. 10-70, at 184; Colonial Gas Company, D.P.U. 84-94, at 22-23 (1984).

The Company accrues incentive compensation costs monthly (Exhs. AG-28-12 (electric); Tr. 10, at 1235-1236). During the last nine months of the test year, the accrual of Incentive Plan costs was based upon expected 2010 payout amounts; during the first three months of the test year, the accrual included a true-up to reconcile the difference between the prior year's expected payout and the actual payout for 2009 (Exhs. AG-28-12 (electric); Tr. 10, at 1234-1236). Both the target amount and the accrual amount are Company estimates of what level of expense will be incurred in the future (Tr. 10, at 1235-1236). Thus, we find that neither the target amount nor the accrual amount is known and measurable.

The Company states that the target incentive compensation amounts normalize the costs at a lower level than the test year amount, which includes incentive compensation payments equal to 133 percent of the target amounts (Exh. MHC-Rebuttal-2, at 2). That is not the case. While the target level of incentive compensation is lower than the accrual amount for direct

Fitchburg employees, the amount allocated from USC is greater than the accrual amount (Exhs. Sch. RevReq-7-1, lines 6, 13 (Supp. 3) (electric); Sch. RevReq-7-3, lines 6, 13 (Supp. 3) (gas); AG-3-6 (electric); AG-7-10 (gas); AG-8-8 (electric)). The aggregate test year payroll, based on the target amount of incentive compensation, is greater than the test year payroll based on the accrued incentive compensation (Exhs. Sch. RevReq-7-1, lines 6, 13 (Supp. 3) (electric); AG-8-8 (electric); Sch. RevReq-7-3, lines 6, 13 (Supp. 3) (gas); AG-7-10 (gas)).

The Department uses test year costs adjusted for known and measurable changes to set distribution rates in accordance with a company's experienced costs. D.T.E. 98-51, at 62; Dedham Water Company, D.P.U. 84-32, at 17 (1984). As we have found above, neither the target amount nor the accrual amount is a known and measurable change. Therefore, the Department finds that the appropriate level of incentive compensation to include in the Company's cost of service should be based on the actual incentive compensation awarded during the test year.

ii. Management Plan

(A) Introduction

Under the Management Plan, certain management employees of Unitil and its subsidiaries, including the Company, are eligible for an annual target incentive award equal to a predetermined percentage of their base salaries, net of any adjustments associated with their 401(k) plans (Exhs. AG-6-5, Att. 2, at 14 (confidential) (electric); AG-6-17, Att. 2, at 1 (electric)). The Management Plan relies on the same performance standards and weightings as the Incentive Plan and uses the same review process (Exhs. AG-6-17, Atts. 2, 5 (electric); AG-5-17 (gas); Tr. 4, at 326-327, 339, 354-356). Therefore, consistent with the results of the Company's Incentive Plan, the Management Plan awards paid out during the test year were equal to 133 percent of the participants' target incentives (Exhs. AG-6-5, Att. 2, at 14 (confidential) (electric); AG-6-17, Atts. 2, 5 (electric); AG-5-17 (gas); Tr. 4, at 354-356).

(B) Positions of the Parties

(1) Attorney General

For the same reasons discussed above regarding the Incentive Plan, the Attorney General argues that the expenses related to the Management Plan should be excluded from the Company's cost of service (Attorney General Brief at 42-43; Attorney General Reply Brief at 17). The Attorney General argues that the Company has failed to demonstrate that the attainment of the financial metrics included in its Management Plan provide a direct benefit to ratepayers and, therefore, that these costs should be excluded (Attorney General Brief at 45-46; Attorney General Reply Brief at 16). Further, the Attorney General argues that the costs of the remaining performance metrics (i.e., gas safety, electric reliability, customer satisfaction, and distribution rates) should also be excluded because they are based on performance data from Unitil's Maine, Massachusetts, and New Hampshire operating subsidiaries and, therefore, are not reasonably designed to encourage good employee performance at Fitchburg (Attorney General Brief at 47, citing Exh. AG-6-17, Att. 5, at 6 (electric); RR-AG-11; RR-AG-15, Att. 1).

(2) Fitchburg

For the same reasons discussed above with respect to the Incentive Plan, the Company argues that the Management Plan is reasonable in amount and reasonably designed to encourage good employee performance (Company Brief at 60-61). Further, the Company argues that it is appropriate to include financial performance measures in its Management Plan because, like its Incentive Plan: (1) the financial performance measures are integrated components of the overall incentive compensation plan and are consistent with plans previously approved by the Department; and (2) the achievement of financial goals delays the need for subsequent rate cases and, therefore, provides a direct benefit to ratepayers (Company Reply Brief at 27).

(C) Analysis and Findings

As we discussed in our analysis above of the Incentive Plan, the Company must demonstrate that the expenses related to its Management Plan are reasonable in amount and that the Management Plan is reasonably designed to encourage good employee performance. D.P.U. 10-114, at 137; D.P.U. 89-194/195, at 34. As part of its Management Plan, the Company paid $20,819 in incentive compensation to Fitchburg’s managers during the test year (Exhs. AG-1-36, Att. 1 (electric); AG-1-36 (gas)). In addition, Unitil awarded $641,663 in incentive compensation to its executives, of which approximately 28.78 percent was allocated to Fitchburg (i.e., $184,671 of which $110,249 was booked to electric operations and $74,422 was booked to gas operations) (Exhs. AG-1-36 & Att. 1 (electric); AG-1-36 (gas)). In total, Fitchburg’s gas and electric cost of service includes $205,490 in incentive compensation costs for Fitchburg’s executives and managers.[115]

[115] Of this amount, approximately 90 percent is incentive compensation for Company officers (Exhs. AG-1-36, Att. 1 (electric); AG-1-36 (gas)).

In D.P.U. 09-01-A, the Department identified numerous deficiencies with respect to Fitchburg's management performance related to Winter Storm 2008. The Department concluded that the Company failed to meet its public service obligation to provide safe and reliable service in multiple aspects of Storm response. D.P.U. 09-01-A at 3, 5, 52, 60, 70, 71-72, 83-84, 121, 125, 135-136. As discussed in Section V, above, we have not faced a like situation where a company so thoroughly mismanaged its response to an event and compromised its responsibilities to the public.

Based on these findings, the Department concludes that Fitchburg's Management Program is not reasonable in design. For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.T.E. 03-40, at 124; D.P.U. 93-60, at 99. As noted above, the Company made an award of incentive compensation to its executives and managers equal to 133 percent of its target in 2009 and 85 percent of target in 2010. The fact that the Management Plan paid any, let alone $205,490, in incentives to reward Fitchburg's executives in the year after Winter Storm 2008 leads us to conclude that the plan is not designed in a way that encourages actions on the part of management to reinforce the Company's public service obligation. Fitchburg's ratepayers clearly did not benefit from management's actions during the Storm. To the contrary, we found that Fitchburg's management did not carry out its public service obligations. See D.P.U. 85-266-A/85-271-A, at 111. While Fitchburg may choose to pay incentive compensation to its executives under such conditions, this compensation must be paid by shareholders and not ratepayers, as we find that the Company has not demonstrated that its Management Plan is reasonably designed to encourage good employee performance.[116]

c. Conclusion

During the test year, Fitchburg employees were awarded $95,752 in incentive compensation payments under the Incentive Plan and Management Plan. In addition, the Company was allocated approximately 28.78 percent of USC's total Incentive Plan and Management Plan awards of $1,733,333 (i.e., $498,853) producing a combined Incentive Plan and Management Plan expense of $594,605 for Fitchburg (Exhs. AG-1-35 (electric); AG-1-35 (gas); Tr. 10, at 1234). Removing the Management Plan award of $205,490 for the reasons discussed above produces a total Incentive Plan payment in the test year of $389,116 (Exh. AG-1-36, Att. 1 (electric)). Based on the 59.7 percent and 40.3 percent allocators for the Company's electric and gas divisions, respectively, $232,302 of this total is allocated to the electric division and $156,814 of this total is allocated to the gas division.

[116] In 2010, Unitil added a provision to its Incentive Plan and Management Plan specifying that the compensation committee can elect to add or subtract up to 25 basis points from the final quantitative results determined by its performance metrics to "reflect unplanned opportunities, unforeseen problems, or otherwise adjust the objective result for unique circumstances that occur during the plan year" (RR-AG-10, Att. 1). Presumably this provision was designed to address situations such as Winter Storm 2008. It is expected that an incentive compensation plan will provide management with a measure of discretion in awarding incentive compensation in a particular year. However, merely adding a discretionary escape clause to an incentive plan that allowed the Company to award incentive compensation to its most senior executives equal to 133 percent of target in 2009 and 85 percent of target in 2010 is not enough to rehabilitate the plan's design.

In order to determine the allowable level of Incentive Plan expense to include in the Company's cost of service, several adjustments are necessary. First, it is necessary to adjust the Company's Incentive Plan expense to recognize capitalized amounts. Using the total incentive compensation capitalization rates of 19.55 percent and 14.83 percent for Fitchburg's electric and gas divisions, respectively, the total portion of Incentive Plan award booked to O&M expense is $320,445. Of this total, $186,887 is allocated to the Company's electric division and $133,558 is allocated to the gas division (Exhs. WP-7-1.3 (Supp. 3) (electric)); WP-7-3.4 (Supp. 3) (gas)).

Next, consistent with the Department's treatment of 401(k) expense, we find it appropriate to recognize the effect of wage and salary increases on the level of incentive compensation to include in cost of service. See D.P.U. 92-250, at 48; Massachusetts Electric Company, D.P.U. 89-194/195, at 39-42 (1990). Therefore, the Department will increase the O&M portion of the Company's incentive plan awards by an aggregate of 3.32 percent to recognize the post-test year union and non-union wage and salary increases allowed by this Order, resulting in increases of $6,198 and $4,439 for the Company's electric and gas divisions, respectively. This adjustment results in a total Incentive Plan award booked to O&M expense of $331,082, consisting of $193,085 and $137,997 for the Company's electric and gas divisions, respectively.

As discussed above, the Department has excluded from Fitchburg's proposed cost of service that portion of Incentive Plan expenses associated with financial performance measures. Therefore, it is necessary to remove the portion of the Company's proposed incentive compensation expense associated with the earnings per share and ROE performance metrics from cost of service.

Incentive compensation awards made during the test year were based on 2008 performance (Exh. AG-6-17, Att. 5, at 2-3 (electric)). The 2008 performance metrics, however, included an O&M expense performance metric that was replaced in 2009 with a gas safety performance metric (Exh. AG-6-17, Att. 5 at 3, 6 (electric)). This change in performance metrics renders the 2008 performance measures unrepresentative for purposes of evaluating the appropriate level of incentive compensation expenses to include in the Company's cost of service.

Fitchburg provided its performance goals for 2010, as well as the payments made based on those goals during 2011 (Exh. AG-6-17, Att. 5, at 8 (electric); RR-AG-10, Att. 1). Therefore, the Department will rely on the Company's performance during 2010 to determine the portion of incentive compensation associated with the earnings per share and ROE metrics.

Fitchburg's 2010 Incentive Plan assign the earnings per share and ROE performance measures weighted values of 25 and 15 percent, respectively (Exh. AG-6-17, Att. 5, at 8 (electric)). Based on the Company's actual performance for that year, Fitchburg failed to achieve its earnings per share threshold but achieved the threshold for its ROE measure

(RR-AG-10, Att. 1). Application of the weighted values assigned to the earnings per share and ROE performance goals for 2010 to the percentage of incentive compensation payable at the respective performance levels results in a weighted value equal to ten percent (i.e., ten percent of total incentive compensation paid in 2011 for 2010 performance was as a result of the achievement of earnings per share and the ROE metrics) (see RR-DPU-10, Att. 1). Therefore, the Department will reduce the Incentive Plan awards for the Company's electric and gas divisions by ten percent. This reduction produces a revised Incentive Plan award of $287,337, consisting of $171,540 allocated to Fitchburg's electric division and $115,797 allocated to Fitchburg's gas division.

Fitchburg proposes to include $294,138 in incentive compensation expense in its electric division cost of service and $198,555 in incentive compensation expense in its gas division cost of service, for a total incentive compensation expense of $492,693 (Exh. AG-28-12, Att. 1 (electric)). Based on the findings above, we have allowed an incentive compensation expense of $171,540 for the Company's electric division and $115,797 for the Company's gas division. Accordingly, the Department will reduce Fitchburg's proposed electric division cost of service by $122,598 and reduce its proposed gas division cost of service by $82,758.

4. Unitil Service Corp. SERP Plan

a. Introduction

Unitil offers a Supplemental Executive Retirement Plan ("SERP") to certain executives of the Company as part of their compensation package (Exh. AG-21-3, Att. 1 (electric)). The SERP is offered by the Board of Directors to encourage service until retirement (Exhs. Unitil-MHC-Rebuttal-2, at 16; AG-DR-1, at 15). The test year SERP expense was $466,500, of which $134,259 (28.78 percent) was allocated to Fitchburg (Exh. AG-21-3, Att. 1 (electric)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that SERP benefits are excessive and, therefore, that they should be excluded from the Company's cost of service (Attorney General Brief at 51). The Attorney General reasons that the four USC executives who receive the SERP benefits are already very well compensated (Attorney General Brief at 51-52). According to the Attorney General, utilities are not typically allowed to recover the cost of their SERP programs from ratepayers (Attorney General Reply Brief at 20, 21, citing Tr. 17, at 2224). Therefore, the Attorney General asserts that, if the Company chooses to award SERP benefits, the costs should be borne by shareholders and not ratepayers (Attorney General Brief at 52).

ii. Fitchburg

The Company argues that the SERP is a component of compensation and is not excessive (Company Brief at 64). According to the Company, the SERP is periodically evaluated by its compensation consultant as part of Unitil's review of overall compensation packages for market competitiveness (Company Brief at 64; Company Reply Brief at 31). Contrary to the Attorney General's assertion, the Company argues that the Department has permitted the costs of SERP programs to be included in rates (Company Reply Brief at 31, citing The Berkshire Gas Company, D.T.E. 01-56, at 86-87 (2002)).

c. Analysis and Findings

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. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach recognizes that the different components of compensation (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. 10-114, at 124; D.P.U. 92-250, at 55.

The purpose of the SERP is to provide an incentive to certain key executives to encourage service until retirement (Exh. Unitil-MHC-Rebuttal-2, at 16). As such, the SERP is considered a part of the overall compensation plan for those executives. The Attorney General does not challenge the usefulness of the SERP in retaining those key executives or the merit of such retention. Rather, her argument is that the executives are already more than adequately compensated and, therefore, that a SERP is excessive and its costs should be disallowed (Attorney General Brief at 51-52).

The Compensation Study considers overall executive compensation relative to similar utilities (Exh. AG-6-5, Att. 2, at 7 (electric)). The Department has reviewed the analysis and found the overall executive compensation levels, including the SERP, to be reasonable. When considered in the context of overall compensation, we do not find the SERP to be excessive or unreasonable. Accordingly, we will permit the Company to include the costs of the SERP in its cost of service.

5. Capitalization of Benefits

a. Introduction

A compensation package is composed of both wages and benefits and, therefore, benefit costs are incurred in the course of employing labor. See D.P.U. 10-114, at 124; D.P.U. 10-55, at 234. Labor is used to install capital investments as well as to implement O&M-related tasks. Therefore, for accounting and ratemaking purposes, the cost of the benefits is allocated between investment and operations. The portion of the costs attributable to capital investment is included in rate base and the portion attributable to O&M is expensed and included in the calculation of O&M expense for base rates.

During the test year, the Company used a capitalization rate of 40.4 percent to capitalize benefits for the electric division and 39.9 percent to capitalize benefits for the gas division (Exhs. AG-1-40, Att. 1 (electric); AG-1-40, Att. 1 (gas)). In calculating its pro-forma medical and dental benefits as well as 401(k) benefits, the Company used a capitalization rate of 33.7 percent (Exhs. WP-7-2.1 (Supp. 3) (electric); WP-7-4.1 (Supp. 3) (gas)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company has improperly used an estimated future capitalization rate to determine the proportion of employee benefits that are expensed (Attorney General Brief at 52; Attorney General Reply Brief at 17-18). Specifically, the Attorney General contends that the Company has not capitalized the benefit costs in proportion to the amount capitalized during the test year (Attorney General Brief at 52). The Attorney General argues that, although the Company appears to be using capitalization rates for wages and salaries based on the test year, the capitalization of benefits for the electric and gas divisions is actually based on the 33.7 percent capitalization rate developed for 2010 (Attorney General Brief at 53).

Finally, the Attorney General argues that the test year amounts of capitalized benefits are in line with the five-year average of the capitalization rates used for benefits (Attorney General Brief at 53). Therefore, the Attorney General asserts that Fitchburg's estimated capitalization rate is not known and measurable (Attorney General Brief at 54). The Attorney General recommends that the Company be required to use the test year capitalization rates of 40.4 percent for the electric division and 39.9 percent for the gas division (Attorney General Brief at 52-54; Attorney General Reply Brief at 18).

ii. Fitchburg

The Company argues that the Department should not accept the Attorney General's recommendation as the projected rate year capitalization rates it uses to capitalize benefits are similar to the rates used during the test year (Company Brief at 78). Furthermore, the Company argues that the proposed capitalization rates represent the Company's best estimate of what the capitalization rates will be for the rate year (Company Brief at 78).

c. Analysis and Findings

In establishing rates for the companies under its jurisdiction, the Department relies on historical test year data, adjusted only for known and measurable changes. D.T.E. 98-51, at 61-62. The selection of a historical twelve-month period of operating data as the basis for setting rates is intended to provide a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Assabet Water Company, D.P.U. 95-92, at 28 (1996); Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); Eastern Edison Company, D.P.U. 1580, at 13-17 (1984).

The rate at which employee wages and benefits are capitalized will vary from year to year depending upon the type and mix of capital projects that a company undertakes in any given year and the particular employees engaged in those projects. D.P.U. 08-35, at 103; D.T.E. 03-40, at 119. In the absence of evidence that the test year capitalization rates are unrepresentative, the Department will apply these rates. The Berkshire Gas Company, D.P.U. 90-121, at 86 (1990).

Fitchburg states that it has applied forecast capitalization rates and argues that use of such rates are appropriate, as they are more representative of the capitalization rates expected to be experienced in the future. However, we find that Fitchburg has failed to demonstrate that its test year capitalization rates are not representative.[117]

117 Although Fitchburg in its third supplemental filing to its revenue requirement schedules purports to use a capitalization rate of 33.7 percent, we conclude that the Company actually capitalized its 401(k) expenses using forecast capitalization rates of 33.7 percent and 33.9 percent for its electric and gas divisions, respectively, and applied capitalization ratios of 41.9 percent and 43.2 percent for its electric and gas divisions, respectively, for other benefits (Exhs. WP-7-2.1 (Supp. 3) (electric); WP-7-4.2 (Supp. 3) (gas); WP-7-4.2 (Supp. 3) (electric); WP-7-6.3 (Supp. 3) (gas)).

Fitchburg's actual test year capitalization rates were 40.4 percent for the Company's electric division and 39.9 percent for its gas division. These rates were similar to the five-year average of 39.1 percent for the period 2006 to 2010 (Exhs. AG-1-40, Att. 1 (electric); AG-1-40, Att. 1 (gas)). Cf. D.P.U. 09-30, at 196-197 (test year capitalization ratio higher than historic ratios for unexplained reasons). Accordingly, the Department finds that Fitchburg's test year capitalization rates are representative of the Company's capitalization rates on a going-forward basis.

Application of the test year electric division capitalization rate of 40.4 percent to the level of benefits allowed in this order results in an increase in the test year cost of service for the Company's electric division of $4,037 (Exh. WP-7-4.2 (Supp. 3) (electric)). Application of the test year gas division capitalization ratio of 39.9 percent to the level of gas division benefits allowed in this Order results in a decrease in the test year cost of service for the Company's gas division of $2,767 (Exh. WP-7-6.3 (Supp. 3) (gas)). Accordingly, the Department will increase the Company's proposed electric division cost of service by $4,037, and will reduce the Company's proposed gas division cost of service by $2,767.

6. Medical and Dental Insurance Expense

a. Introduction

During the test year, the Company booked $457,335 in medical and dental expenses to its electric division, including $200,690 allocated from USC (Exh. Sch. RevReq-7-2 (Supp. 3) (electric)). The Company proposes to increase medical and dental expense for its electric division by $32,495 (Exh. Sch. RevReq-7-2 (Supp. 3) (electric)).[118] Of the $32,495 proposed increase, Fitchburg assigns $3,066 to internal transmission and the remaining $29,439 to base distribution (Exh. Sch. RevReq-7-2 (Supp. 3) (electric)).

During the test year, the Company booked $471,076 in medical and dental expenses to its gas division, including $206,720 allocated from USC (Exh. Sch. RevReq-7-4 (Supp. 3) (gas)). The Company proposes to decrease medical and dental expense for its gas division by $2,634 (Exh. Sch. RevReq-7-4 (Supp. 3) (gas)).[119] (Exh. RevReq-7-4 (Supp. 3) (gas)).

To determine its pro-forma medical and dental insurance expense, the Company based the calculation on the enrollments as of December 31, 2009, and premium rates effective January 1, 2010. The Company then made adjustments based on its projected future hiring of

[118] The proposed increase consists of $30,884 in direct expenses to the Company and $1,611 in allocated expenses from USC (Exh. Sch. RevReq-7-2 (Supp. 3) (electric)).

[119] The proposed net decrease consists of an $8,157 increase in direct expenses to the Company and a decrease of $10,791 allocated expenses from USC (Exh. Sch. RevReq-7-4 (Supp. 3) (gas)).

employees to fill open positions (Exhs. AG-8-10 (electric); WP-7-2.1 (Supp. 3) (electric); WP-7-2.2 (Supp. 3) (electric); WP-7-4.1 (Supp. 3) (gas); WP-7-4.2 (Supp. 3) (gas); Tr. 10, at 1245).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's claim that it will fill the open positions during the rate year is speculative and, therefore, that the adjustment for additional employee enrollments should be rejected (Attorney General Brief at 54-55; Attorney General Reply Brief at 28). According to the Attorney General, the Company's employee head counts were approximately the same in December 2009, December 2010, and February 2011, and, therefore, the Company has presented insufficient evidence that additional enrollments in its medical and dental insurance plans will take place (Attorney General Brief at 55, citing Exhs. AG-DJE, at 6 (electric); AG-DJE, at 6 (gas)).

ii. Fitchburg

Fitchburg argues that it has taken effective measures to contain medical and dental costs such as requiring employees to pay 20 percent of premiums, requiring non-union employees to enroll in a health plan with a high deductible and accompanying health savings account and increasing its level of stop-loss coverage (Company Brief at 48-49). In addition, the Company argues that the adjustments made to the medical and dental expense for expected enrollments comply with the Department precedent (Company Brief at 48, citing D.T.E. 01-56, at 60; D.P.U. 96-50, at 45-46; D.P.U. 86-86, at 8).

c. Analysis and Findings

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

The Department finds that Fitchburg has taken reasonable and effective measures to contain its health care costs (see, e.g., Exhs. Unitil-GEL-1, at 11-13 (electric); AG-6-11 (electric); AG-6-12 (electric); AG-6-13 (electric); AG-6-14 (electric); AG-5-11 (gas); AG-5-12 (gas); AG-5-13 (gas); AG-5-14 (gas)). For example, Fitchburg has replaced the indemnity insurance plan for union employees with a point of service plan at an estimated annual savings of $236,174 (Exhs. Unitil GEL-1, at 11 (electric); AG-6-11 (electric); AG-5-11 (gas)). The Company converted from a self-insured plan with an estimated savings in 2001 of $691,090 (Exhs. Unitil GEL-1, at 12 (electric); AG-6-13 (electric); AG-5-13 (gas)). The Company replaced its preferred provider plan with a consumer directed health plan[120] with a co-insurance feature and premiums approximately 30 percent lower than those of its previous plan

[120] The consumer-directed health plan is a high deductible health insurance plan and a health savings account (Exhs. Unitil-GEL-1, at 12 (electric); Unitil-GEL-1, at 11 (gas)).

(Exhs. Unitil-GEL-1, at 12 (electric); AG-6-10 (electric); AG-5-10 (gas)). In addition, Fitchburg has been able to obtain stop loss insurance with better rates (Exh. AG-6-10 (electric); AG-5-10 (gas)).

As of December 31, 2009, Fitchburg had five open positions and Unitil had eight open positions (Exhs. WP-7-2.1, 2.2 (Supp. 3) (electric); WP-7-4.1, 4.2 (Supp. 3) (gas); Tr. 10, at 1244). The open positions are the result of retirements or terminations (Tr. 10, at 1245). The Company has not demonstrated that the open positions have been filled; rather, it has indicated that the positions remain open (Exhs. MHC-Rebuttal-2, at 4; AG-8-10 (electric); Tr. 10, at 1245). Accordingly, the Department finds that Fitchburg has failed to demonstrate that its proposed adjustment to test year medical and dental expenses to account for these future employees is known and measurable. Accordingly, the Department will remove the proposed medical and dental expenses associated with these open positions from the Company’s cost of service. In addition, consistent with our findings above, the Department will apply an electric division capitalization rate of 40.4 percent and a gas division capitalization rate of 39.9 percent to the Company’s medical and dental insurance expenses. The result of these two adjustments reduces the Company’s proposed medical and dental insurance expense to $449,922 for the electric division and by $439,406 for the gas division. Accordingly, the Department will reduce the Company’s proposed cost of service by $39,908 for the electric division and by $29,036 for the gas division.

B. Uncollectible Expense

1. Introduction

A distribution company recovers uncollectible expense (i.e., bad debt) associated with both commodity ("supply-related bad debt") and retail distribution service ("distribution-related bad debt"). See, e.g., D.P.U. 07-71, at 106. Fitchburg's gas division has been recovering supply-related bad debt on a dollar-for-dollar basis pursuant to its Cost of Gas Adjustment Clause ("CGAC") tariff since January 1, 2006. See D.T.E. 06-109, at 4; Fitchburg Gas and Electric Light Company, D.T.E. 05-GAF-P4, Stamp-Approval of Tariff M.D.T.E. No. 123 (December 15, 2005). Fitchburg's electric division has been recovering supply-related bad debt on a dollar-for-dollar basis through its Basic Service Costs Adder since December 1, 2005. See D.P.U. 07-71, at 106-109; Fitchburg Gas and Electric Light Company, D.T.E. 05-GAF-P4/06-28, at 7 (2006).[121]

[121] On December 22, 2005, the Department approved revisions to Fitchburg's CGAC tariff, which allowed the Company to recover for the first time, on a dollar-for-dollar basis, gas supply-related bad debt effective January 1, 2006. D.T.E. 05-GAF-P4, Stamp-Approval of Tariff M.D.T.E. No. 123; see also D.T.E. 05-GAF-P4/06-28, at 1 & n.1. On September 7, 2006, the Department approved Fitchburg's proposal to recover, on a dollar-for-dollar basis, electric supply-related bad debt effective December 1, 2005. D.T.E. 05-GAF-P4/06-28, at 7. The Department consolidated both dockets. D.T.E. 05-GAF-P4/06-28, at 1. As discussed below, the Attorney General appealed the Department's Order in D.T.E. 05-GAF-P4/06-28 to the Supreme Judicial Court. The Court issued a decision: (1) vacating the Department's stamp-approval of the CGAC tariff; (2) vacating the D.T.E. 05-GAF-P4/06-28 Order; and (3) remanding the case to the Department for further proceedings. Attorney General v. Department of Public Utilities, 453 Mass. 191, 202 (2009).

Regarding distribution-related bad debt, the Department permits a representative level of bad debt expense to be included in cost of service. D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. During the test year, Fitchburg booked $514,532 and $508,654 to distribution-related uncollectible expense for its gas and electric divisions, respectively (Exhs. Sch. RevReq-7-7 (Supp. 3) (gas); Sch. RevReq-7-5 (Supp. 3) (electric)).[122] The Company proposes to increases its distribution-related bad debt expense by $28,190 and $30,396 for its gas and electric divisions, respectively (Exhs. Sch. RevReq-7-7 (Supp. 3) (gas); Sch. RevReq-7-5 (Supp. 3) (electric)).[123] For both the gas and electric divisions, Fitchburg proposes to calculate the total amount of distribution-related bad debt to be included in distribution rates by dividing the 2007 through 2009 three-year average delivery-related net write-offs as a percentage of total delivery revenues for the corresponding period and multiplying the resulting percentage by normalized test year delivery revenues (Exhs. Unitil-MHC-1, at 24-25 (gas); Unitil-MHC-1, at 29 (electric)).

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[122] The Company's test year amount of distribution-related bad debt expense for the electric division is exclusive of $12,644 in bad debt expense assigned to internal transmission (Exh. Sch. RevReq-7-5 (Supp. 3) (electric)). To determine the amount assigned to internal transmission, the Company multiplied the proposed uncollectible distribution revenue requirement by the company's internal transmission allocator (i.e., 2.4292 percent) (Exh. Sch. RevReq-7-5 (Supp. 3) (electric)).

[123] The Company's proposed increase to its distribution-related bad debt expense for the electric division is exclusive of $757 in expense assigned to internal transmission. (Exh. Sch. RevReq-7-5 (Supp. 3) (electric)).

2. Positions of the Parties

a. Attorney General

i. Supply and Distribution Write-Offs

The Attorney General argues that Fitchburg has systematically overcharged its customers for supply-related bad debt expense since the Department began allowing the Company to recover supply-related bad debt on a dollar-for-dollar basis on December 1, 2005 (Attorney General Brief at 69; Attorney General Reply Brief at 33). While its total write-offs remain the same, the Attorney General asserts that the Company has learned to "game" the apportionment of bad debt so that it assigns and, thereby recovers, more bad debt as supply-related, which is recovered on a dollar-for-dollar basis, than distribution-related bad debt, which is not recovered dollar-for-dollar (Attorney General Brief at 69).

More specifically, the Attorney General argues that prior to 2005, the Company's net write-offs to revenues ratios for supply- and distribution-related bad debt for both the electric and gas divisions were almost the same (Attorney General Brief at 73, 75). The Attorney General asserts, however, that starting in 2006 after the Company began recovering supply-related bad debt on a dollar-for-dollar basis, the net write-off ratio for supply-related bad debt has been consistently much larger than the net write-off ratio for distribution-related bad debt (Attorney General Brief at 73, 75). Specifically, the Attorney General argues that by 2009: (1) the gas division's write-off percentage for supply-related bad debt was more than 72 percent higher than the write-off percentage for distribution-related bad debt; and (2) the electric division's write-off percentage for supply-related bad debt was more than 118 percent higher than the write-off percentage for distribution-related bad debt (Attorney General Brief at 73, 75).

To address the alleged overcharging of customers for supply-related bad debt, the Attorney General recommends that the Department direct the Company to return $332,134 to gas ratepayers through the CGAC and $588,222 to electric ratepayers through the Basic Service Costs Adder (Attorney General Brief at 76). According to the Attorney General, these amounts represent the difference in the Company's: (1) actual net write-off percentage from 2006 through 2009; and (2) average net write-off percentage for both the gas and electric divisions during the same period (Attorney General Brief at 73, 75, 76).

The Attorney General claims that the Company's argument that its billing system is automated and, therefore, cannot be manipulated is contradicted by the fact that in many other cases the Department has recognized billing and revenue write-offs that occurred outside of a company's accounting system (Attorney General Reply Brief at 34, citing D.P.U. 09-30, at 247-250). Further, the Attorney General argues that the Department has previously adjusted Fitchburg's bad debt expense to remove extraordinary write-offs that the Company booked manually (Attorney General Reply Brief at 34, citing D.T.E. 02-24/25, at 169-170). Therefore, the Attorney General contends that Fitchburg cannot rely on the argument that its billing system is automated to explain the disproportionate increase in supply-related bad debt compared to distribution-related bad debt (Attorney General Reply Brief at 33-34).

As to Fitchburg's argument that the difference in supply and delivery write-offs could be due to a timing difference between when revenues are recorded and when write-offs occur, the Attorney General argues that this justification could explain discrepancies only in terms of months, not years (Attorney General Reply Brief at 34). The Attorney General further asserts that, even if there is a time lag and change in the relative amounts of delivery and supply revenues, the percentage net write-off lag should, over time, average out to be about the same (Attorney General Reply Brief at 34).

Finally, the Attorney General argues that the Company's contention that large C&I customers are a cause of supply-related write-offs does not explain the increase in supply-related write-offs since the Company began collecting supply-related bad debt on a dollar-for-dollar basis (Attorney General Reply Brief at 35). According to the Attorney General, large customers have been purchasing their own supply and taking distribution-only service since the 1990s but the Company has offered no plausible reason why these customers would suddenly cause higher supply-related write-offs (Attorney General Reply Brief at 35).

ii. Supreme Judicial Court Remand

Noting that the Supreme Judicial Court vacated the Department's Orders in D.T.E. 05-GAF-P4 and D.T.E. 06-28 and ordered a remand for further proceedings, the Attorney General argues that Fitchburg is required to provide its customers with a refund of bad debt costs collected under the tariffs that the Supreme Judicial Court invalidated (Attorney General Brief at 70 n. 15).

b. Fitchburg

i. Supply and Distribution Write-Offs

The Company asserts that the Attorney General's argument that it has been overcharging customers for supply-related bad debt is: (1) not factually correct; (2) not based on evidence of any improper action by the Company; and (3) based solely on the fact that the Company's bad debt write-off percentage for supply is higher than the bad debt write-off percentage for distribution (Company Brief at 71; Company Reply Brief at 39). First, the Company asserts that supply-related bad debt is verifiable through the billing system (Company Reply Brief at 40, citing D.T.E. 03-40, at 266-267). Specifically, the Company maintains that the calculation of supply-related bad debt occurs within the billing system and is not a function of a manual calculation (Company Brief at 71). According to the Company, its billing system tracks revenues and accounts receivables by individual billing component, and as cash is posted to an account, the billing system distributes the cash proportionately between the distribution and non-distribution components without human intervention or manipulation of the amounts (Company Reply Brief at 39-40).

Next, the Company argues that the bad debt write-off percentage for supply is expected to be higher than the bad debt write-off percentage for distribution because the relationship between revenues and write-offs is not established over a short time period, as the Attorney General suggests (Company Reply Brief at 40). Rather, the Company claims that write-offs can occur several months to more than a year after bills are issued (Company Reply Brief at 40). For example, the Company states that customers who are protected from service shut-offs, such as those who are eligible for winter-moratorium protection, can skew the write-off percentage because these customers accumulate higher supply-related costs during the winter months, which are not written off until months later, when the winter moratorium ends (Company Reply Brief at 40). Further, the Company argues that supply rates can vary greatly from season to season and year to year, while distribution rates remain fairly steady, further contributing to the low correlation between a particular year's distribution versus supply write-offs (Company Brief at 72, citing Tr. 15, at 1835-1836; Tr. 18, at 2495-2496; Company Reply Brief at 40-42).

Finally, the Company argues that large C&I customers purchasing competitive supply also contribute to the difference in bad debt write-off percentages (Company Brief at 72; Company Reply Brief at 41). Specifically, the Company contends that the percentage of C&I customers purchasing supply from third parties is increasing, resulting in an increase in the number of customers that contribute distribution revenue but not supply revenue (Company Reply Brief at 41). Although these customers cause supply revenues to decrease when they switch to competitive supply, Fitchburg argues that they have little effect on distribution write-offs because these customers account for only a small percentage of total write-offs (Company Reply Brief at 41). Accordingly, the Company argues that distribution-only C&I customers cause the bad debt write-off percentage for supply to be higher than the bad debt write-off percentage for distribution (Company Reply Brief at 41).

3. Analysis and Findings

a. Calculation of Distribution-Related Bad Debt

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 (2009); 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, the appropriate method to calculate distribution-related bad debt is to remove all revenues relating to supply from the company's bad debt calculations. See D.P.U. 07-71, at 106-109.

The method used by Fitchburg to calculate its distribution-related bad debt adjustment is consistent with Department precedent (Exhs. Unitil-MHC-1, at 29 (electric); Sch. RevReq-7-5 (Supp. 3) (electric); Unitil-MHC- 1, at 25 (gas); Sch. RevReq-7-7 (Supp. 3) (gas)). 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. However, the Company applied the three-year average bad debt rate to both the test year retail billed revenues and the requested distribution rate increase (Exhs. Sch. RevReq-7-5 (Supp. 3) (electric); Sch. RevReq-7-7 (Supp. 3) (gas)). Accordingly, because the Department has not approved the distribution rate increase as proposed, the bad debt adjustment is overstated.

Applying the three-year average bad debt rate of 2.92 percent to test year revenues for the gas division of $14,033,661 yields a distribution-related bad debt expense of $409,783.

Further, applying the three-year average bad debt rate of 2.92 percent to the allowed distribution revenue increase of $3,197,780 for the gas division results in an additional $93,375 of bad debt expense.[124] Accordingly, we find that the Company's allowed distribution-related bad debt expense is $503,123 for the gas division

Applying the three-year average bad debt rate of 1.29 percent to the test year revenues for the electric division of $36,111,844 yields a distribution-related bad debt expense of $465,842. Further, applying the three-year average bad debt rate of 1.29 percent to the allowed distribution revenue increase of $3,275,871 for the electric division results in an additional $42,259 of bad debt expense. Finally, removing the revenues allocated to internal transmission reduces distribution-related bad debt expense for the electric division by $12,342.[125] Accordingly, we find that the Company's distribution-related bad debt expense is $496,786 for the electric division.

b. Supply and Distribution Write-Offs

The Attorney General argues that since the Department first approved dollar-for-dollar recovery of supply-related bad debt in 2005, the Company has manipulated its calculation of bad debt in order to categorize more bad debt expense as supply-related (Attorney General Brief at 70). To support her argument, the Attorney General compares the company's net

[124] The $3,197,780 only includes distribution-related costs as shown in Schedule 10 (gas).

[125] Internal transmission is calculated by applying the Company's internal transmission allocation factor of 2.4292 percent to the approved electric division revenue requirement in this case (Exhs. Unitil-MHC-1, at 29 (electric); Sch. RevReq-7-5 (Supp. 3) (electric)); WP-3-3 (electric)).

write-offs before the Department allowed dollar-for-dollar recovery of bad debt (i.e., 2005) and the Company's net write-offs after the Department allowed dollar-for-dollar recovery (i.e., 2006 through 2009) (Attorney General Brief at 72, 74, citing Exhs. AG-3-12, Att. 1 (electric); AG-8-27, Att. 1 (gas)). From 2005 to 2009, supply write-offs for Fitchburg's gas division increased from 2.34 percent in 2005 to 4.91 percent in 2009, while distribution write-offs remained relatively stable (Attorney General Brief at 72, citing Exh. AG-8-27, Att. 1 (gas)). Similarly, for its electric division, supply write-offs increased from 1.32 percent in 2006 to 2.55 percent in 2009, while distribution write-offs remained relatively stable (Attorney General Brief at 74, citing Exh. AG-3-12, Att. 1 (electric)).

Despite the trends in net write-offs observed by the Attorney General, there is no evidence to indicate that the Company is manipulating its billing system in order to categorize more bad debt as supply-related than distribution-related. Rather, the evidence demonstrates that Fitchburg's billing system allocates revenues between supply and distribution proportionally based on individual customer usage and that the Company does not perform manual calculations (Exhs. Unitil-MHC- 1, at 29 (electric); Unitil-MHC- 1, at 24-25 (gas); Tr. 15, at 1826-1828; RR-AG-50). See D.T.E. 03-40, at 266-267 (approving proposal to recover supply-related bad debt based on the company's ability to track actual monthly supply write-offs from distribution write-offs using its billing system); cf. D.P.U. 09-30, at 248-249 (declining to accept the company's bad debt calculation because, among other reasons, the write-off amounts were not verified through the billing system or otherwise).

There are many factors that could cause the differences in the bad debt ratios for supply and distribution identified by the Attorney General. Such factors include changes in the basic service rate, the number of customers that have switched to a competitive supplier, and the lag in write-offs related to the winter moratorium.[126]

For the reasons discussed above, we find that the remedy suggested by the Attorney General is not warranted. The Department will continue to carefully monitor the collection of supply-related bad debt in the Company's CGAC and basic service reconciliation proceedings.

As a final matter, we note that the Company has recently implemented measures designed to reduce both its collection lag and level of uncollectables such as the addition of an automated system to contact delinquent residential customers, a program coordinator to manage its arrearage management program, and a customer assistance program coordinator (Exh. DPU-12-4 (electric)). Nonetheless, the Department is concerned about the magnitude of the increase in the Company's write-offs in recent years (Exhs. AG-3-12, Att. 1 (electric); AG-8-27, Att. 1 (gas)). In order to allow the Department to evaluate the Company's efforts to reduce its collection lag and level of uncollectibles, the Department directs the Company to

[126] The Company's write-offs have historically occurred six months to a year or more after an account becomes unpaid (Tr. 15, at 1829). Several factors can contribute to this lag in write-offs. One factor is the five-month winter moratorium period in which Fitchburg's gas division typically bills about 80 percent of its sales and cannot terminate service for non-payment (Tr. 3, at 294; Tr. 4, at 400-402). Bills not paid during the winter moratorium could result in large write-offs at the end of the moratorium period, which could skew write-offs to supply revenue ratios. See D.T.E. 02-24/25, at 169 (recognizing that winter moratorium may result in increases to the level of write-offs).

provide, as part of its annual Basic Service Costs Adder Reconciliation filing and in its semi-annual CGAC filings, a monthly accounting of delivery revenues, supply revenues, and net write-offs for both delivery and supply.[127]

c. Supreme Judicial Court Remand

As discussed above, the Supreme Judicial Court has vacated and remanded to the Department for further proceedings our Order in D.T.E. 05-GAF-P4/06-28, at 7, which permitted the Company to recover its actual gas supply-related bad debt on a dollar-for-dollar basis effective January 1, 2006, and actual electric supply-related bad debt effective December 1, 2005. 453 Mass. at 202. The Court's decision was based on a determination that the Department failed to satisfy the procedural due process requirements of G.L. c. 164, § 94 before approving the tariff revisions, because the revisions represented a general increase in rates. 453 Mass. at 198.

In the interim between the Order in D.T.E. 05-GAF-P4/06-28 and the Supreme Judicial Court's decision, the Company filed two rate cases. In setting new electric distribution rates in D.P.U. 07-71, the Department approved dollar-for-dollar collection of supply-related bad debt for Fitchburg's electric division. Similarly, in approving a settlement between the Company and the Attorney General for an increase in gas distribution rates in D.T.E. 06-109, the Department approved dollar-for-dollar collection of supply-related bad debt for Fitchburg's gas division. Because the Supreme Judicial Court's decision was based on procedural and not

[127] The Company should refer to the information provided in Exhibits AG-3-12, Att. 1 (electric) and AG-8-27, Att. 1 (gas) as a guide in preparing these filings.

substantive grounds, the Department's subsequent approval of dollar-for-dollar recovery of bad debt in D.P.U. 06-109 and D.P.U. 07-71, respectively, wherein the Department satisfied the public hearing and notice requirements of G.L. c. 164, § 94, remains valid.

In the instant proceedings, the Attorney General argues that the Department should require Fitchburg to refund all bad debt costs collected under the tariffs that the Supreme Judicial Court invalidated in 453 Mass. 191 (Attorney General Brief at 70 n. 15). The notices in the instant proceedings, however, were not designed to inform the parties to D.T.E. 05-GAF-P4/06-28 that the Department would address the remand of those matters here. Accordingly, the Department will not address any issues related to the remand and raised by the Attorney General in these proceedings. Instead, the Department will conduct further proceedings in D.T.E. 05-GAF-P4/06-28 to address Fitchburg's dollar-for-dollar collection of supply-related bad debt during the period between when the Department first approved this method in D.T.E. 05-GAF-P4/06-28 and the Company's subsequent gas division and electric division rate cases in D.T.E. 06-109 and D.P.U. 07-71, respectively.[128]

[128] For the gas division, the relevant time period is between January 1, 2006, the effective date of the CGAC tariff that the Department approved in D.T.E. 05-GAF-P4, and February 1, 2007, the effective date of the new gas distribution rates approved in the rate case settlement in D.T.E. 06-109. For the electric division, the relevant time period is December 1, 2005, pursuant to D.T.E. 05-GAF-P4/06-28, at 7, and March 1, 2008, the date the new electric distribution rates took effect pursuant to D.P.U. 07-71.

C. Rate Case Expense

1. Introduction

Initially, Fitchburg estimated that it would incur $1,136,206 in rate case expense for its electric division and $700,475 in rate case expense for its gas division (Exhs. Sch. RevReq-7-9 (electric); Sch. RevReq-7-9 (gas)). Fitchburg's proposed rate case expenses include expert services related to: (1) legal representation; (2) accounting cost of service analysis, marginal cost of service analysis, rate design analysis, and related services;[129] (3) cost of capital and return on equity analysis; (4) depreciation studies; (5) lead-lag studies; (6) a line loss study for the electric division; (7) revenue requirements analysis;[130] (8) a revenue decoupling proposal;[131] (9) miscellaneous costs associated with preparing the rate case, including temporary help,

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[129] As described more fully below, the Company selected one consultant and its subcontractor to perform work on these issues (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); AG-5-12 (electric); DPU-6-15, Att. 1 (Supp. 2) (gas); AG-3-12 (gas); Tr. 7, at 669-670). Additionally, that same consultant was selected to perform the depreciation study, the lead lag study, the line loss study, and portions of the revenue requirements work (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas). Hereinafter this consultant will be referred to as the "rate design consultant" and its subcontractor will be referred to as the "rate design consultant's subcontractor."

[130] The Company's rate case expense estimate for its electric division revenue requirement consultant includes consultant fees related to its cost recovery proposal for Winter Storm 2008 and its vegetation management program proposal (Exhs. Sch. RevReq-7-9 (electric); DPU-8-12 (electric); DPU-21-8 (electric); Sch. RevReq-7-9 (gas); DPU-6-12 (gas); DPU-20-8 (gas)).

[131] The Company's rate case expense estimate for revenue decoupling services includes consultant fees related to the Company's participation in D.P.U. 07-50-A (Exhs. DPU-8-13 (electric); DPU-21-9 (electric); DPU-20-9 (gas)).

printing, transcripts, courier and delivery services, newspaper publication; and (10) legal services related to responding to oversight questions issued by the Attorney General pursuant to G.L. c. 12, § 11E (Exhs. Sch. RevReq-7-9 (electric); DPU-8-6, Att. 1, at 1-2 (electric); DPU-8-16, Att. 1 (electric); AG-5-12 (electric); Sch. RevReq-7-9 (gas); DPU-6-6 (gas); DPU-6-15, Att. 1 (gas); AG-3-12 (gas)). To the extent that consultant charges are common to both rate cases, the Company proposes to allocate costs using its net revenue allocation factors (Exhs. DPU-8-19 (electric); DPU-6-19 (gas)).

Based on its final invoices and projected costs to complete the compliance filing,[132] Fitchburg proposes a final rate case expense for its electric division of $1,010,811 and a rate case expense for its gas division of $665,537, for a total rate case expense of $1,676,348 (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); Sch. RevReq-7-9 (Supp. 3) (gas)). Fitchburg proposes to normalize its rate case expense over four years for both its electric and gas divisions (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); Sch. RevReq-7-9 (Supp. 3) (gas)). Normalizing the proposed rate case expense of $1,010,811 for Fitchburg's electric division over four years produces an annual expense of $252,703 (Exh. Sch. RevReq-7-9 (Supp. 3) (electric)). Normalizing the proposed rate case expense of $665,537 for Fitchburg's gas division over four years produces an annual expense of $166,384 (Exh. Sch. RevReq-7-9 (Supp. 3) (gas)).

[132] As discussed below, Fitchburg proposes to include the following amounts in rate case expense for work to complete the compliance filing: (1) legal services: $8,936 for the electric division and $6,065 for the gas division; (2) rate design consultant: $1,790 for the electric division and $2,450 for the gas division; and (3) decoupling consulting services: $861 for the electric division and $584 for the gas division (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General contends that the Company bears the burden of demonstrating that its selection of outside service providers is prudent and appropriate (Attorney General Brief at 81). The Attorney General asserts that, in doing so, the Company is required to provide an adequate justification and showing, with contemporaneous documentation, that its choice of outside services was reasonable and cost-effective (Attorney General Brief at 79, citing D.P.U. 07-71, at 139-140; D.T.E. 03-40, at 153; D.T.E. 02-24/25, at 192; D.T.E. 98-51, at 61). Further, the Attorney General argues that the Company has an affirmative duty to contain rate case expense and that the Department has repeatedly expressed concern about high levels of rate case expense (Attorney General Brief at 79, citing D.P.U. 08-35, at 129; D.P.U. 07-71, at 90; D.T.E. 98-51, at 57; D.P.U. 93-60, at 145; D.P.U. 92-111, at 208; D.P.U. 92-78, at 58). The Attorney General also notes that the Department will "scrutinize the overall level of rate case expense and may require shareholders to shoulder a portion of the expense" (Attorney General Brief at 79, citing D.P.U. 08-35, at 135).

Regarding the Company's selection of specific rate case consultants, the Attorney General argues that Fitchburg has not met its burden to justify recovery of rate case expenses related to the following: (1) a vegetation management budget consultant; (2) a consultant retained to assess the costs associated with Winter Storm 2008; and (3) the Company's inclusion of decoupling-related consulting costs associated with work performed in a prior docket (Attorney General Brief at 78-82). The Attorney General's arguments with respect to these categories of expenses are summarized below.

ii. Vegetation Management Program Consultant and Winter Storm 2008 Cost Consultant

The Attorney General challenges the costs associated with the Company's vegetation management program consultant and the Company's Winter Storm 2008 cost consultant for failure to engage in a competitive solicitation. First, the Attorney General argues that these costs should be excluded from rates as de facto imprudent because they were not selected through a competitive bidding process in violation of Department precedent (Attorney General Brief at 79-80, citing ; D.P.U. 10-55, at 341; D.T.E. 03-40, at 149). According to the Attorney General, without engaging in a competitive bidding process, the Company cannot met its burden to prove that its selection of outside consultants was prudent and appropriate (Attorney General Brief at 81-82, citing D.P.U. 08-35, at 130-131; D.T.E. 03-40, at 153). Further, the Attorney General contends that the Company's failure to engage in a competitive bidding process undermines the Department's goal of preventing consultants from taking their relationship with the Company for granted (Attorney General Brief at 82, citing D.P.U. 09-30, at 230). Thus, the Attorney General argues that without a competitive bidding process, the Department has no objective measure to determine whether the services could have been performed at a lower cost by a comparable consultant and ultimately, whether the consultant took advantage of a prior relationship (Attorney General Brief at 82, citing D.P.U. 09-30, at 230; D.P.U. 07-71, at 139-140; D.T.E. 02-24/25, at 192; D.T.E. 98-51, at 61).

The Attorney General also argues that these costs should be excluded from rates because Fitchburg has not adequately justified its decision to forgo a competitive solicitation for its vegetation management program and Winter Storm 2008 cost recovery consultants, again in contravention of Department precedent (Attorney General Brief at 81, citing D.T.E. 03-40, at 153-154). The Attorney General contends that the Company's only explanation for not engaging in a competitive solicitation – that the Company had previously engaged the consultants to perform similar services – is insufficient and has been rejected by the Department in similar cases (Attorney General Brief at 81, citing D.T.E. 03-40, at 148-152; Tr. 7, at 646, 647). Further, the Attorney General argues that Company's justification is insufficient because it does not provide any factual or objective basis for concluding that these consultants would be better or more reasonably priced than other outside consultants (Attorney General Brief at 81). In addition, the Attorney General argues that the Company has failed to demonstrate that the selection of these consultants was prudent and appropriate because it has provided no documentation of a well analyzed decision-making process, as required by the Department (Attorney General Brief at 82, citing D.P.U. 09-39, at 287; D.T.E. 03-40, at 153).

iii. Revenue Decoupling Consultants

The Attorney General also challenges the Company's request to recover costs associated with the Company's revenue decoupling consultant in connection with work performed in D.P.U. 07-50 (Attorney General Brief at 82). Specifically, the Attorney General asserts that, consistent with Department precedent, these costs should be excluded because they were incurred prior to the test year in these cases (Attorney General Brief at 83, citing Fitchburg Gas and Electric Light Company, D.T.E. 99-118, Interlocutory Order Regarding Scope of Proceeding and Motion to Compel Discovery at 8 (2001); D.P.U. 95-92, at 28; Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); Eastern Edison Company, D.P.U. 1580, at 13-17 (1984)). Accordingly, the Attorney General contends that the Department should exclude from recovery costs associated with work performed in D.P.U. 07-50 in the amount of $124,137 for the Company's electric division and $95,517 for the Company's gas division, or a total of $219,654 (Attorney General Brief at 82, 84, citing Exhs. Sch. RevReq-7-9 (electric); Sch. RevReq-7-9 (gas); Attorney General Reply Brief at 36-37).[133]

[133] The $219,654 in decoupling costs the Attorney General seeks to exclude from rate case expense represented, at the time of her brief, the Company's total expenditures for its decoupling consultant including costs for work done in D.P.U. 07-50 as well of costs incurred in the instant rate cases to support the Company's decoupling proposals (Exhs. DPU-8-16, Att. 1 (Supp. 1) (electric); DPU-6-15, Att. 1 (Supp. 1) (gas)).

b. Fitchburg

The Company argues that its vegetation management consultant was originally selected through a competitive bidding process to perform a vegetation management study and then called upon in these proceedings to explain its recommendations (Company Brief at 73, citing Tr. 7, at 646-647). Accordingly, the Company argues that it has met the Department's requirements with respect to competitive bidding for this consultant (Company Brief at 73).

In addition, the Company acknowledges that it is seeking recovery for some work done by its decoupling consultant in D.P.U. 07-50, but only to the extent that it directly related to the Company's decoupling proposal in the instant rate case filings (Company Brief at 73-74, citing Tr. 7, at 638). Further, the Company claims that the work performed by the decoupling consultant in the prior docket helped form the foundation for the Company's instant decoupling proposals and helped the Company avoid some initial costs in developing the decoupling proposal (Company Brief at 74, citing Tr. 7, at 638).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has actually been incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 219-220; D.P.U. 09-30, at 227; 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. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 219-220; D.P.U. 09-39, at 290-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 153. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 219-220; D.P.U. 10-55, at 323; see D.P.U. 93-223-B at 16. Moreover, in its continuing scrutiny of the overall level of rate case expense, the Department may require shareholders to shoulder a portion of the expense. D.P.U. 10-114, at 219-220; D.P.U. 08-35, at 135.

b. Competitive Bidding

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with the competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective, and based on a request for proposals ("RFP") process that is fair, open, and transparent. See D.P.U. 10-114, at 221; 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. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFPs issued to solicit consultants must clearly identify the scope of work to be performed and the criteria by which the consultants will be evaluated. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for rate case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expenses, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

As noted above, the Attorney General contests the Company's proposed rate case expenses related to two consultants – the Winter Storm 2008 cost recovery consultant and the vegetation management consultant – on the grounds that these consultants were not selected through a competitive bidding process.

ii. Fitchburg's RFP Process

The Company initially intended to file rate cases in November 2009 and, therefore, issued an RFP for non-legal services on April 7, 2009 (Exhs. DPU-8-1, at 1 (electric); AG-5-1, Att. 1 (electric)). However, the Company did not file its rate cases in November 2009 as expected. Fitchburg initially delayed its rate case filings until the first or second quarter of 2010 (Exhs. DPU-8-1 (electric) at 1; AG-5-1, Att. 2 (electric), at 1; DPU-6-1(gas)). After an additional delay, the instant rate cases were filed in January 2011.

The Company issued the non-legal RFP to eight potential bidders. The service list for this RFP was based on the Company's past experience with certain consultants, bidders in other Massachusetts utility rate case RFPs, and internet searches (Exhs. AG-5-6, Att. 1, at 1 (electric); AG-3-6 (gas)).

The non-legal RFP sought bids for the following categories of services: (1) cost of service studies, allocated cost of service studies, marginal cost studies, and rate design;[134] (2) a line loss study for the electric division; (3) depreciation studies; (4) cost of capital analysis; and (5) analysis regarding revenue decoupling and performance based rate ("PBR") plans (Exhs. AG-5-1 Att.1, at 2-4 (electric); AG-5-6, Att. 1, at 1 (electric); AG-3-1 (gas)). The RFP required respondents to submit bids that included work for both the gas and electric divisions and permitted respondents to bid on one or more of the non-legal service categories (Exhs. AG-5-1 Att. 1, at 1 (electric); AG-3-1(gas)).

Seven bidders responded to the non-legal RFPs, with a number of respondents providing bids for multiple categories of non-legal services (Exhs. AG-5-6, Att. 1, at 1 (electric); AG-3-6 (gas)).[135] The Company states that it organized evaluation teams to assess

[134] The RFP for the cost studies and rate design proposal also indicated that the Company would consider proposals related to the lead-lag studies (Exhs. AG-5-1, Att. 1 (electric); AG-3-1, Att. 1 (gas)).

[135] The number of bidders responding in each category was as follows: (1) cost of service studies, allocated cost of service studies, marginal cost studies, and rate design – five bidders; (2) line loss study for the electric division – three bidders; (3) depreciation studies – four bidders; (4) cost of capital – three bidders; and (5) revenue decoupling and PBR plans – five bidders (Exh. AG-5-6, Att. 1, at 1).

the bids by service category (Exh. AG-5-6, Att. 1, at 2 (electric); AG-3-6 (gas)). The evaluation teams reviewed the bids, and scored and evaluated them based on corporate capability,[136] project team capability, technical approach,[137] proposal quality, pricing, and commercial review[138] (Exhs. AG-5-6, Att. 1, at 2 (electric); AG-3-6 (gas)). With respect to price, the Company focused on the "not to exceed" bids for work performed through the rate case filing stage, and the hourly rates for post-filing work (Exhs. AG-5-6, Att.1, at 2; (electric); AG-3-6 (gas)).

On November 16, 2009, the Company issued an RFP for legal services to eight potential bidders (Exhs.DPU 8-1, at 1 (electric); DPU-8-3, at 1 (electric); DPU-6-3 (gas)).

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136 The Company considered the following factors, among others, when assessing corporate capability: (1) whether the Company had previous positive experience with a bidder; (2) whether the bidder demonstrated knowledge about the subject matter; (3) whether the bidder had provided the type of service before; and (4) whether the bidder would use experienced staff on the project (Exh.AG-5-6, Att. 3 (electric)).

137 For the technical approach measure, the Company considered: (1) the bidder's response to the RFP requirements; (2) whether the bid contained a work breakdown of project tasks and the staff assigned to each task; (3) whether the work breakdown was appropriate and complete and indicated that the bidder understood scope of assignment; (4) whether the response included an outline of the planned schedules and workpapers that would support the findings and recommendations; and (5) proposed innovative approaches (Exh. AG-5-6, Att. 3 (electric)).

138 For the commercial review measure, the Company considered: (1) whether the bidder had any commercial impediments to completing the project; (2) whether the bidder had adequate resources to meet the deadlines; and (3) whether the bidder provided a schedule to meet the deadlines (Exh. AG-5-6, Att. 3 (electric)).

Fitchburg received responses to this RFP from six law firms (Exhs. DPU-8-3, at 1 (electric); DPU-6-3 (gas)). The Company rejected two bids due to cost concerns (Exhs. DPU-8-3, at 1 (electric); DPU-6-3 (gas)). The Company's chief regulatory counsel conducted interviews with the remaining four law firms (Exhs. DPU-8-3, at 1 (electric); DPU-6-3 (gas)).

As detailed above, following the RFP process in 2009 the Company had received bids from a variety of legal and non-legal consultants. However, given the delay between these solicitations and the actual filing of the rate cases, the Company states that it followed up with bidders to confirm their bids (Tr. 7, at 625-626). According to the Company, it was able to negotiate a lower bid for its selected legal consultant, while the other legal and non-legal respondents held firm to their original bids (Tr. 7, at 627).

Based on the foregoing, the Department finds that the Company conducted a fair, open, and transparent RFP process to generate bids from potential non-legal and legal consultants. We conclude that the RFPs clearly identified the scope of work to be performed and the criteria by which the consultants would be evaluated (Exhs.DPU-8-1 (electric); DPU-8-3 (electric); DPU-8-3, Att. 1 (electric); AG-5-1, Atts. 1, 2 (electric); AG-5-6, Atts. 1-7 (electric); AG-3-6 (gas)). Further, we conclude that Fitchburg's bid evaluation process was adequately structured to allow the Company to determine the capabilities, approach, and pricing offered by the various service providers (Exhs.DPU-8-1 (electric); DPU-8-3 (electric); DPU-8-3, Att. 1 (electric); AG-5-1, Atts. 1, 2 (electric); AG-5-6, Atts. 1-7 (electric); AG-3-6 (gas)). Below, we address the Company's selection of particular rate case consultants.

c. Fitchburg's Rate Case Consultants

i. Vegetation Management Consultant

In D.P.U. 09-01-A at 160, the Department directed Fitchburg to engage a contractor, selected through a competitive solicitation, to assist the Company in developing and improving its tree trimming practices. The Department also directed the Company to "submit a revised vegetation management program and policy for Department review." D.P.U. 09-01-A at 160. Although the Department did not direct Fitchburg to file this vegetation management program report for Department review as part of the Company's next rate case, the Company chose to do so (Exhs. Unitil-EC/AP-1, at 2-3 (electric); Unitil-EC/AP-2 (electric)).[139] The Company seeks to include in its electric division rates $45,269 in costs associated with the presentation of this report by the Company's vegetation management consultant (Exhs. DPU-8-16, Att. 1 (electric); Unitil-EC/AP-1, at 2-3 (electric); Unitil-EC/AP-2 (electric)).[140]

The Company argues that one purpose of the consultant's testimony in this case was to support the need for a significant increase in the Company's vegetation management budget

[139] The Company submitted the consultant's vegetation management report to the Department, for the first time, with its rate case filing on January 14, 2011 (Exh. Unitil-EC/AP-2, at 1 (electric)). We note that the report is dated June 9, 2010, seven months prior to the Company filing its rate case (Exh. Unitil-EC/AP-2, at 1 (electric)).

[140] The $45,269 in costs does not include any costs related to the preparation of the report itself (Tr. 7, at 660).

(Exh. Unitil-EC/AP-1, at 3 (electric)).[141] However, in order to consider the Company's request for an increase in its vegetation management budget, the Department was first required to review the methods of analysis and the ultimate findings contained in the consultant's vegetation management report. [142] As a result, discovery and cross-examination of the Company's witness focused primarily on understanding and testing the methods, conclusions, and recommendations in the report (see, e.g., Exhs. AG-10-21 through AG-10-43; Tr. 10, at 1250-1253, 1266-1267, 1285, 1291-1294).

As noted above, the Company was obligated to engage a consultant to improve its tree trimming practices and to develop a revised vegetation management program and submit it to Department for review regardless of whether or when the Company intended to file a rate case. See D.P.U. 09-01-A at 160. The fact that the Company chose to present this consultants' report for review in the instant rate proceeding does not automatically render the costs associated with presenting the report rate case expense.[143]

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141 As discussed in Section X.O below, the Department has denied the Company's request for an increase in its vegetation management budget because we conclude that (1) the Company's proposed vegetation management budget does not constitute a known and measureable post-test year change that permits an adjustment, and (2) vegetation management expenses are not the type of cost that should be the subject of a new reconciling mechanism.

142 The Company itself acknowledges that one purpose of the consultant's testimony in this case was "to review the methodology and findings of [the] consultant's analysis" (Exh. Unitil-EC/AP-1, at 3 (electric)).

143 We note that the costs in question were incurred in 2010 and 2011, outside of the test year in D.P.U. 11-01 (Exh. DPU-8-16, Att. 3, Tab 6, at 1-32 (Supp. 1) (electric)). Accordingly, as a regulatory expense, the costs associated with the consultant's presentation of the vegetation management report for Department review are already supported by the Company's distribution rates in force in 2010 and 2011.

Rate case expense is limited to outside services procured for the preparation and presentation of a petition to increase rates under G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et seq. The Company has failed to identify what portion of the consultant's work was solely related to its request for an increase in its vegetation management budget and clearly incremental to work that was required to present the vegetation management report for Department review pursuant to our directives in D.P.U. 09-01-A (Exh. Unitil-EC/AP-1, at 3 (electric)). Accordingly, we disallow recovery of $45,269 in costs associated with the Company's vegetation management consultant. [144]

ii. Winter Storm 2008 Cost Recovery Consultant

The Company seeks to include in its electric division rates as rate case expense $58,841 in costs related to its Winter Storm 2008 cost recovery consultant (Exh. DPU-8-16, Att. 1 (electric)). The Attorney General objects to these costs on grounds that the Company did not engage in a competitive solicitation prior to retaining this consultant (Attorney General Brief at 81). The Company states that it selected this consultant because it had direct experience in conducting post-storm reviews and the Company was satisfied with the firm's work on its behalf in other management consulting engagements (Exh. DPU-8-2 (electric); Tr. 7, at 649-651). Further, the Company notes that this consultant conducted a management review of the Company's storm costs following Winter storm 2008 and, as such, was the logical choice to present those findings to the Department (Tr. 7, at 649-651).

144 As we have disallowed these costs on other grounds, we need not address the Attorney General's challenge to the costs on the grounds that the Company did not engage in a competitive solicitation (see Attorney General Brief at 80).

The Company did not engage in a competitive solicitation for this consultant (Exh. DPU-8-2 (electric); Tr. 7, at 649-651). The consultant was first retained in or around March 2010 to review and verify the Company's costs relating to Winter Storm 2008 (Tr. 10, at 1331-1332). At that time, the Company was already in the process of preparing the instant rate cases (see, e.g., Exhs. DPU-8-16, at Att. 3, Tab 14 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 15 (Supp. 1) (gas)). The storm cost recovery consultant was again retained in November 2010 to provide testimony in the instant cases supporting the Company's proposal to recover costs related to Winter Storm 2008 (Exh. AG-5-7, Att. 6, at 1 (electric)).

We find that when Fitchburg initially hired the Winter Storm 2008 cost recovery consultant in March 2010, the Company knew or should have known that it might also need to present that consultant as a witness in an upcoming rate case. Indeed, when the Company sought Department approval to defer these costs for potential future recovery in rates, the Company made clear that it considered these costs to be an integral part of any upcoming rate case. See D.P.U. 09-61 (2009). As we noted in our Order in approving the deferral of these costs:

> The Company asserts that if the Department approves the Company's request to defer the storm costs, the Company anticipates filing a rate case in the second quarter of 2010, using a 2009 calendar year test year. If its deferral request is not approved, however, the Company represents that it will file a rate case in 2009 using either a calendar year 2008 test year or a split test year covering July 1, 2008 through June 30, 2009 to ensure Winter Storm 2008 costs are included in the test year for rate setting purposes.

D.P.U. 09-61, at 3-4 (internal citations omitted). Clearly, the Company planned to seek recovery of these storm costs in the instant rate cases. It was reasonable to expect that the Company would need to establish a basis for recovery of these costs by sponsoring the Winter Storm 2008 cost recovery consultant as a witness.

Based on these considerations, we find that the Company should have followed long-standing Department precedent and competitively solicited the Winter Storm 2008 cost recovery services prior to retaining its consultant in March 2010. Competitive bidding for outside rate case services is the norm and the Company has not demonstrated that the facts surrounding the retention of the Winter Storm 2008 cost recovery witness rose to the most unusual circumstances sufficient to relieve it from compliance with the competitive bidding requirement. D.P.U. 10-55, at 342.

To allow recovery of these storm cost consultant costs would permit the Company to avoid the Department's requirement that companies engage in competitive bidding processes for outside rate case services. Without a competitive solicitation, we find that the Company has provided insufficient evidence to show that the consultant's expenses are reasonable, appropriate, and prudently incurred. See D.P.U. 10-114, at 219-220; D.P.U. 09-30, at 227; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14. Nor has the Company shown that it attempted to contain costs associated with these services. See D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. Accordingly, we disallow $58,841 in costs associated with the Company's Winter Storm 2008 cost recovery consultant.

iii. Revenue Decoupling Consultants

(A) Introduction

The Company seeks to include as rate case expenses in its electric and gas division rates three categories of expenses related to revenue decoupling. First, the Company seeks to include $108,425 in its electric division rates and $71,764 in its gas division rates for costs associated with the consultant chosen to prepare and present the decoupling proposals in the instant rate cases (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-8-16, Att. 3, Tab 4 (Supp. 1) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas); DPU-6-15, Att. 3, Tab 4 (Supp. 1) (gas)). Second, the Company seeks to include $31,507 in its electric division rates and $21,661 in its gas division rates for costs associated with various consultants' work performed in D.P.U. 07-50-A and D.P.U. 07-50-B (hereinafter, "generic decoupling proceedings") (Exhs. DPU-8-16, Att. 1 (Supp. 1) (electric); DPU-6-15, Att. 1 (Supp. 1) (gas)). Third, the Company seeks to recover costs of $861 for its electric division and $584 for its gas division related to the Company's decoupling proposals for completion of the rate cases, through the compliance stage (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)).[145] Neither the Attorney General nor any other party challenges the first or third category of costs. However, the Attorney General objects to the recovery of rate case expenses associated with the generic decoupling proceedings.

145 The proposed rate case expenses for completion of the compliance filing are addressed separately below.

(B) Revenue Decoupling Proposals

The Company seeks to include $108,425 in its electric division rates and $71,764 in its gas division rates for costs associated with its consultant's preparation of the decoupling proposals in the instant rate cases. The Company conducted a competitive solicitation prior to engaging the services of its decoupling consultant (Exhs. DPU-8-1, Att. 1 (electric); AG-5-6, Att. 1, at 1 (electric); AG-3-6 (gas)). Fitchburg issued an RFP to eight potential decoupling consultants and received responses from five bidders (Exhs. DPU-8-1, Att. 1 (electric); AG-5-6, Att. 1, at 1 (electric); AG-3-6 (gas)). The RFP clearly set forth the scope of the work to be performed and the criteria upon which each bidder would be evaluated (Exh. AG-5-1, Att. 1, at 3-4, 5-13 (electric)). The chosen consultant was not the lowest of the five bidders (Exh. AG-5-6, Att. 2, at 9-10 (electric)).

Obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder. The need to contain rate case expense, however, must be accorded a high priority in the review of bids received for rate case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. 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, in seeking recovery of rate case expenses, companies must demonstrate that their choice of consultants is both reasonable and cost-effective. See D.P.U. 10-114, at 222; D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153. This burden is heightened where the Company did not choose the lowest bidder,[146] and the best evidence to aid the Company in satisfying its burden is contemporaneous documentation of its well-analyzed decision-making. D.P.U. 10-114, at 227; D.P.U. 08-35, at 130-121; D.T.E. 03-40, at 83-84, 153. To make such findings, the Department must examine Fitchburg's bid evaluation process.[147]

As part of its bid evaluation process, the Company eliminated the highest bidder from consideration based on price (Exh. AG-5-6, Att. 2, at 10 (electric)). The Company also rejected the lowest overall bidder based on (1) a lack of relevant experience in the gas and electric industries, the subject of decoupling, and the Massachusetts regulatory environment; and (2) a failure to detail the proposed work or demonstrate its technical approach (Exh. AG-5-6, Att. 2, at 9 (electric)). We find that the Company's decision to reject these two bidders was reasonable.

With respect to the remaining three bidders (including the selected bidder) the Company determined that all three were experienced in decoupling and familiar with the Massachusetts regulatory environment (Exh. AG-5-6, Att. 2, at 9 (electric)). The chosen consultant provided the second highest bid (Exh. AG-5-6, Atts. 2, 5 (electric)). The Company

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146 While the Company competitively bid the majority of its rate case services, it did not choose the bidder with the lowest total bid for any of the RFP areas (see, e.g., Exhs. AG-5-6, Att. 2, at 1-10 (electric); AG-5-6, Att. 5, at 1-2 (electric)).

147 We note that Fitchburg provided the Department with contemporaneous documentation of its bid evaluation process sufficient for us to review the reasonableness of the Company's decision making process (Exhs. AG-5-6, Atts. 1-7 (electric)).

selected this consultant after determining that it rated somewhat higher than the remaining two consultants in non-price categories, particularly in project team capability and technical approach (Exh. AG-5-6, Att. 2, at 9-10 (electric)). In choosing this consultant, the Company also considered its positive experience with the selected consultant in other matters and the consultant's direct experience with revenue decoupling in Massachusetts (Exh. AG-5-6, Att. 2, at 10 (electric)). Finally, Fitchburg weighed the selected consultant's close physical proximity to the Company as a benefit that would provide flexibility to schedule in-person meetings on short notice (Exh. AG-5-6, Att. 2, at 10 (electric)).

It is important to note that while Fitchburg stated that the lower cost bidder ("Consultant B") and the selected consultant were comparable on pricing, and scored them equally on price, the record shows that the bids differed by over $22,000 (Exh. AG-5-6, Att. 5, at 1-2 (electric)). Therefore, we find that Consultant B clearly should have received a higher score on price (Exh. AG-5-6, at 1 (electric)).

Further, although the Company ranked its chosen consultant slightly higher on the more subjective non-price criteria, we find that the lower-priced Consultant B, who was well known to the Company, was comparably qualified to do the work in this case (Exh. AG-5-6, Att. 2, at 9 (electric)). Our findings are based on our review of the bids and are supported by the Company's own bid evaluation (Exhs. AG-5-4, Att. 2 (electric); AG-5-6, Att. 5 (electric) 1-2; AG-5-6, Att. 2).

A review of Consultant B's bid shows that the consultant had previously worked with several utilities on revenue decoupling proposals (Exh. AG-5-4, Att. 6, at 26-27 (electric)). Additionally, Consultant B had previously worked with the Company on its performance based rate proposals before the Department and also assisted the Company with a developmental assessment on ratemaking approaches including revenue decoupling (Exh. AG-5-4, Att. 6, at 3). As noted above, the Company determined that Consultant B was experienced in decoupling and familiar with the Massachusetts regulatory environment (Exh. AG-5-6, Att. 2, at 9 (electric)). The Company stated that it had direct experience with Consultant B and rated Consultant B equally on corporate capability with the chosen consultant, giving both consultants the highest rating possible (Exhs. AG-5-6, Att. 2, at 9 (electric); AG-5-6, Att. 4, at 5 (electric)). Further, while the Company rated Consultant B slightly lower than its chosen consultant on project team capability, the Company noted that Consultant B had highlighted "a number of experiences and relevant clients" (Exhs. AG-5-6, Att. 2, at 9 (electric); AG-5-6, Att. 4, at 5 (electric)). While the Company rated Consultant B lower on technical approach because it was "not as strong on direction," it also noted that Consultant B "showed understanding" of the scope of the assignment (Exhs. AG-5-6, Att. 2, at 9 (electric); AG-5-6, Att. 4, at 5 (electric)). The Company also rated Consultant B lower on proposal quality but stated that Consultant B's "proposal quality was very good" and provided no detail as to what earned it a lower score (Exh. AG-5-6, Att. 2, at 9). The Company also rated Consultant B and its chosen consultant equally on the commercial review measure because Consultant B demonstrated that it could meet the filing deadlines and had no conflicts of interest (Exhs. AG-5-6, Att. 2, at 10 (electric); AG-5-6, Att. 4, at 5 (electric)).

In seeking recovery of rate case expenses, Fitchburg must provide an adequate justification and showing that its choice of consultant is both reasonable and cost-effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. While the overall scores for the two consultants were not equal in the Company's bid evaluation, we find that the Company did not provide sufficient evidence to show that its choice of a higher priced consultant in this instance was reasonable and cost-effective when a lower priced, experienced and qualified consultant who was well known to the Company was available and capable of completing the work on time.[148] As we have stated before, the need to contain rate case expense must be accorded a high priority in the review of bids received for rate case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The Company failed to do so here.

We will not substitute our judgment for that of Fitchburg in determining which consultant may be best suited to serve its interests and, therefore, the Company was free in this instance to choose the services of the higher priced bidder. However, where a comparably qualified lower priced bidder is available to do the work, the additional cost of the higher bidder must be borne by shareholders and not ratepayers. See D.P.U. 93-60, at 46-47 (cost of "luxury" vehicles for company executives in excess of certain amount excluded from rate base).

[148] We give little weight to the benefits assigned in the Company's bid analysis to the chosen consultant's close proximity to Fitchburg. The Company testified that it is successful at communicating in many ways that do not require travel or in-person meetings (Tr. 7, at 667-669, 676-678). In any event, Consultant B's bid was lower than the chosen consultant, even after accounting for travel expenses (Exh. AG-5-4, Att. 2, at 44 (electric)).

We find that the bid provided by Consultant B provides the benchmark of reasonableness for the costs of providing decoupling services in this case.[149] Accordingly, we disallow $22,858 associated with the Company's decoupling consultant to account for the difference in the bids between Consultant B and the selected consultant. This disallowance will be allocated to the electric division in the amount of $13,617 and to the gas division in the amount of $9,241.[150]

With the exception of the costs addressed above, the Department finds that the Company employed appropriate cost-containment measures with respect to the selected consultant. For example, the consultant provided certain consulting services at a fixed cost and was subject to a "not to exceed" cap on its estimate for time and materials, which resulted in billing adjustments of approximately $75,000 ($45,249 for the electric division and $30,558 for the gas division) (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); AG-5-4, Att. 3, at 119-120 (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)).

[149] Consultant B provided a bid that was $22,858 lower than the selected consultant. This amount is inclusive of the estimates for work through filing and work post-filing (Exh. AG-5-6, Att. 5, at 1 (electric)).

[150] This allocation was based on the Company's 2010 allocation factor (Exhs. DPU-8-19 (electric); DPU-6-19 (gas)). This factor was chosen because the decoupling consultant incurred more costs in 2011 than it did in the each of the prior years.

(C) D.P.U. 07-50 Expenses

As stated above, the Company seeks to include in rates costs associated with various consultants' work in 2007 for testimony and other services relating to the Department's generic decoupling proceedings (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)). The Attorney General challenges these costs as non-test year expenses (Attorney General Brief at 83; Attorney General Reply Brief at 36-37).

We find that these costs are not appropriate for recovery as rate case expense. Although the Company argues that the expenses at issue are directly relevant to the Company's decoupling proposal in the instant rate case filings and, further, that such work helped the Company avoid some costs in this rate case, these costs were incurred more than three years prior to the rate case filings and in relation to a different proceeding (Company Brief at 74, citing Tr. 7, at 638). They cannot be categorized as rate case expense simply because they are associated with subject matter (i.e., the revenue decoupling proposals) that is being addressed in these proceedings. Companies often engage outside counsel or consulting services as part of normal operations, and the costs at issue for the generic decoupling proceedings amount to consulting services that were already supported by ordinary rates in force in 2007. Rate case expense, however, is limited to outside services procured for the preparation and presentation of a petition to increase rates under G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et seq. The Company has failed to meet its burden to demonstrate that the costs at issue were for the preparation and presentation of the current cases. Accordingly, we disallow $53,168 in costs associated with the generic decoupling proceedings; consisting of $31,507 in costs allocated to the electric division and $21,661 in costs allocated to the gas division.

iv. Remaining Rate Case Consultants

The Company seeks to include in rates the expenses associated with its (1) cost studies and rate design consultant and its subcontractor;[151] (2) cost of capital and ROE consultant; and (3) legal counsel (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); DPU-8-16, Att. 1 (Supp. 2) (electric); Sch. RevReq-7-9 (Supp. 3) (gas); DPU-6-15, Att. 1 (Supp. 2) (gas)). Fitchburg engaged in a competitive bidding process for each of the above three categories of service providers (Exhs. DPU-8-1 Att. 1 (electric); DPU-8-3 (electric); AG-5-3 (electric); AG-5-6, Att. 1, at 1 (electric); AG-3-6 (gas)). The selected service providers did not offer the lowest price for their respective services (Exhs. AG-5-4, Atts. 12, 14 (confidential) (electric); AG-5-6, Att. 2, at 1, 7 (electric); AG-5-6, Att. 5, at 1 (electric); AG-3-6 (gas)).[152]

Neither the Attorney General nor any other party challenges the Company's retention of these consultants or the costs associated with their services. Nevertheless, Fitchburg bears the

151 The Company chose one consultant and that consultant's subcontractor to perform work on the accounting cost of service analysis, marginal cost of service analysis, rate design analysis, electric division line loss study, lead-lag studies, and depreciation studies (Exhs. DPU-8-16, Att. 1 (Supp. 1) (electric); DPU-6-15, Att. 1 (Supp. 1) (gas)).

152 The rate design consultant provided separate bids on all of the categories of services for which it was retained (Exhs. AG-5-4, Att. 5 (electric); AG-5-6, Att. 5, at 1 (electric)). These separate bids were higher than those received by other bidders for these services (Exhs. AG-5-6, Atts. 2, 5 (electric)). However, the rate design consultant's overall bid for all of these services combined was lower than the lowest bids for the individual services combined (Exh. AG-5-6, Atts. 2, 5 (electric)).

burden to demonstrate that its choice of consultants is both reasonable and cost-effective. See D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153. Further, this burden is heightened where the Company did not choose the lowest bidder. D.P.U. 10-114, at 227; D.P.U. 08-35, at 130-121; D.T.E. 03-40, at 83-84, 153.

Based on our review of the bids as well as Fitchburg's bid evaluation processes, for each category of services we conclude that Fitchburg's choice of consultants was both reasonable and cost-effective. We find that the Company gave proper consideration to price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU-8-3 (electric); DPU-21-20 (electric); AG-5-4, Att. 5, at 1, 3 (electric); AG-5-4, Att. 11, at 3-16 (electric); AG-5-4, Att. 12 (electric); AG-5-6, Att. 1, at 1 (electric); AG 5-6 Att. 2, at 1, 5, 7-8 (electric); AG-5-6, Att. 5, at 1, 3-4 (electric)). We find that, for each category the Company appropriately selected a consultant who possesses expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which each consultant was requested to bid (Exhs. DPU-8-3 (electric); AG- 5-4, Att. 5 at 1, 3 (electric); AG-5-4, Att. 11, at 5-16 (electric); AG-5-6, Att. 2, at 4, 7-8 (electric); AG-5-6, Att. 5 (electric)).

Further, based on our review of the bids and the Company's bid evaluations, we find that the Company adequately supported its decision not to choose lower priced bidders for these services because they had less experience in the relevant areas, less direct experience with Fitchburg, provided less desirable fee structures, and in some cases did not demonstrate sufficient knowledge or understanding of the scope of work (Exhs. AG-5-6, Att. 2 (electric); DPU-8-3 (electric)).

In addition, we conclude that the Company selected consultants that offered the Company adequate cost-control measures. For example, with respect to the rate design consultant and its subcontractor, the Company combined overlapping subject matter areas into one category and coordinated between Fitchburg's internal staff and the selected consultants to keep costs low (Exhs. DPU-21-20 (electric); AG-5-4, Att. 5, at 16 (electric); AG-5-6, Att. 1, at 1 (electric)). Additionally, the rate design consultant and the Company agreed to implement "not to exceed" price caps on portions of the selected consultant's work and the subcontractor discounted travel time by 50 percent (Exhs. DPU-21-20 (electric); AG-5-4, Att. 5, at 16 (electric); AG-5-6, Att. 1, at 1 (electric)). With respect to the cost of capital and ROE consultant, the Company and the consultant agreed to implement "not to exceed" price caps (Exh. AG-5-4, Att. 4, at 4 (electric)). With respect to legal services, the selected law firm provided a discounted blended hourly rate for all attorneys working on the case and also provided an estimate of the total number of hours and amount of reimbursable expenses for completion of the rate case, based on what it considered to be a similar proceeding before the Department (Exh. AG-5-4, Att. 11 (confidential) (electric)). The overall discount and blended rate were not inconsequential reductions from the rates normally charged by the lead attorneys assigned to the case (Exh. AG-5-4, Att. 12 (confidential) (electric)). Additionally, the retained legal services bidder did not seek reimbursement for mileage, parking, transportation or meals (AG-5-4, Att. 11, at 3-4 (electric)).

Finally, with several exceptions discussed in the section below, we find that the total costs associated with each service provider were not unreasonable or disproportionate to the overall scope of work provided (Exhs. DPU-21-20 (electric); AG-5-4, Att. 4, at 4 (electric); AG-5-4, Att. 5, at 16 (electric); AG-5-4 Att. 11, at 4 (electric); AG-5-4, Att. 12 (electric); AG-5-6, Att. 1, at 1 (electric); AG-5-6, Att. 5 (electric)).

d. Various Rate Case Expenses

i. Rate Case Consultant Costs

Regarding the service providers discussed above, we find that certain expenses were imprudently incurred or otherwise not appropriate to pass on to ratepayers. Specifically, we disallow excessive costs associated with two upgraded airline flights taken by the Company's cost of capital consultant for a total of $1,028 ($613 for the electric division and $416 for the gas division).[153] The Company stated that it expects its rate case consultants to use coach fares (Tr. 7, at 676-678). While reasonable travel expenses may be appropriate, we find that the upgraded flights are solely related to the consultant's personal travel preferences and are not required to perform rate case services.[154] Accordingly, the Company may not collect such

153 These amounts were allocated based on the Company's 2010 allocation which applies to costs incurred in 2011.

154 We note that another consultant who flew on an upgraded flight using the same airline discounted that flight to the coach-equivalent fare when it billed the Company for its services and also provided a listing of the daily fares in support of the invoice and discount calculation (Exhs. DPU 8-16, Att. 1, Tab 16, at 7-10 (Supp. 1) (electric); DPU 6-15, Att. 1, Tab 16, at 7-10 (Supp. 1) (gas)). However, such a detailed listing was not provided by the cost of capital consultant.

costs from its ratepayers. Likewise, we disallow charges for valet parking for the Company's rate design consultant totaling $76 for the electric division and $76 for the gas division (Exhs. DPU-8-16, Att. 3, Tab 14, at 215-216 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 15, at 178-179 (Supp. 1) (gas)).

ii. Abandoned Test Year Costs

(A) Introduction

The Company engaged the following consultants on June 4, 2009, and they began work on a rate case that was expected to be filed in November of that year: (1) rate design consultant; (2) rate design consultant's subcontractor; and (3) decoupling consultant (Exhs. DPU-8-1, at 1-2 (electric); DPU-8-16, Att. 3, Tab 3, at 4-7; Tab 14, at 3; Tab 16, at 3 (Supp. 1) (electric); AG-5-1, Att. 1 (electric); DPU-6-1, at 2 (gas); DPU-6-15, Att. 3, Tab 3, at 4-7; Tab 15, at 3; Tab 16, at 3 (Supp. 1) (gas); Tr. 7, at 625-627). The Company did not file its rate case in November 2009 and, at that time, indicated that it planned to delay the filing to the first or second quarter of 2010 (Exhs. DPU-8-1, at 1 (electric); AG-5-1 Att. 2, at 1 (electric)). Ultimately, the Company filed the instant rate cases on January 14, 2011.

As a result of these delays, the record in these proceedings contains invoices from the aforementioned three consultants that include work based on three different test years: (1) a test year ending December 2008 (Exhs. DPU 8-16, Att. 3, Tab 16, at 5 (Supp. 1) (electric);

DPU-6-15, Att. 3, Tab 16, at 5 (Supp. 1) (gas)); (2) a split test year ending June 30, 2009 (Exhs. DPU 8-16, Att. 3, Tab 16, at 19 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 16, at 19 (Supp. 1) (gas)); and (3) test year ending 2009 (Exhs. DPU 8-16, Att. 3, Tab 16, at 45 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 16, at 45 (Supp. 1) (gas)). The rate design consultant's subcontractor specifically identified in its invoices which of the three test years were being used as the basis of its services at various points in time (Exh. DPU 8-16, Att. 3, Tab 16, at 5, 19, 45 (Supp. 1) (electric)). The other two consultants' invoices do not contain specific references to which of the three test years the work pertains (Exhs. DPU-8-16, Att. 3, at Tabs 3, 14, 16 (Supp. 1) (electric); DPU-6-15, Att. 3, at Tabs 3, 15, 16 (Supp. 1) (gas)). However, the record indicates that the rate design consultant and the decoupling consultant performed rate case related work at the same time as the rate design consultant's subcontractor (Exhs. DPU-8-16, Att. 3, at Tabs 3, 14, 16 (Supp. 1) (electric); DPU-6-15, Att. 3, at Tabs 3, 15, 16 (Supp. 1) (gas)). Based on a review of these invoices and the other evidence regarding the Company's decision to delay its rate case filing, we conclude that all three of these consultants worked simultaneously on the same test years during the relevant time periods (Exhs. DPU-8-1, at 1 (electric); AG-5-1 Att. 2, at 1 (electric); Tr. 7, at 625-627).

(B) Test Year Ending December 2008

Based on a review of the record, we find that the Company has failed to demonstrate that work performed from June 2009 through August 2009 for rate cases with a 2008 test year was either relevant or useful to the instant rate case filings (Exhs. DPU-8-16, Att. 3, Tab 3, at 1-10; Tab 14, at 1-32; Tab 16, at 1-16 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 3, at 1 10; Tab 15, at 1-25; Tab 16, at 1-16 (Supp. 1) (gas)). The work performed on the abandoned test year amounted to consulting services already supported by ordinary rates in force in 2009. See D.T.E. 03-40, at 156. It led to no result and cannot be recovered as rate case expense. See D.T.E. 03-40, at 156-157 (denying legal expenses incurred in preparation of an abandoned rate case, when the company delayed filing and ultimately filed using a later test year). Rather, the evidence only supports a finding that the Company began work on a rate case that it later decided not to file. See D.T.E. 03-40, at 155-156. Accordingly, we disallow expenses associated with the Company's rate design consultant in the amounts of $15,269 for the electric division[155] and $10,420 for the gas division.[156] Similarly, we disallow expenses associated with the Company's rate design consultant's subcontractor in the amounts of $12,357 for the electric division[157] and $6,361 for the gas division.[158] With respect to the Company's decoupling consultant, no adjustment is necessary because the Company reduced

155 This amount represents the totals for all invoices reflecting work prior to August 1, 2009 (see Exhs. DPU-8-16, Att. 2, at 4 (Supp. 2) (electric); DPU-8-16, Att. 3, Tab 14, at 1-32 (Supp. 1) (electric)).

156 This amount represents the totals for all invoices reflecting work prior to August 1, 2009 (see Exhs. DPU-6-15, Att. 2, at 4 (Supp. 2) (gas); DPU-6-15, Att. 3, Tab 15, at 1-25 (Supp. 1) (gas)).

157 This amount represents the totals for all invoices reflecting work prior to August 1, 2009 (see Exhs. DPU-8-16, Att. 2 (Supp. 2) (electric); DPU-8-16, Att. 3, Tab 16, at 1-16 (Supp. 1) (electric)).

158 This amount represents the totals for all invoices reflecting work prior to August 1, 2009 (see Exhs. DPU-6 15, Att. 2, at 6 (Supp. 2) (gas); DPU-6-15, Att. 3, Tab 16, at 1-16 (Supp. 1) (gas)).

several bills in 2010 totaling $45,249 for the electric division and $30,558 for the gas division pursuant to previously agreed upon spending limits (Exhs. DPU-8-16, Att. 1 (electric); DPU-6-15, Att. 1 (gas)).[159] We find, therefore, that the total proposed costs for the decoupling consultant do not contain costs associated with any duplication of effort as a result of Company's decision to change the test year.

(C) Split Test Year Ending June 30, 2009

Based on a review of the record, we find that the Company has adequately demonstrated that work performed from August 2, 2009 through January 30, 2010,[160] was relevant and useful to the instant rate case filings (Exhs. DPU-8-16, Att. 3, Tab 3, at 1-16; Tab 14, at 33-84; Tab 16, at 17-42 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 3, at 1-16; Tab 15, at 26-61; Tab 16, at 17-42 (Supp. 1) (gas)). While the Company ultimately had to update some data and schedules, the Department is satisfied, based on the amount of time spent and nature of the consultants' work, that the consultant expenses during this time period were not meaningfully duplicated later and did not otherwise increase rate case expense when the test year was changed. Accordingly, we will allow these costs, subject to any adjustments made in other sections of this Order.

159 Had the billing limit adjustments not been made, a total of $26,684 (allocated between the electric and gas divisions) for work performed prior to August 1, 2009, would have been excluded on grounds that the work was done for the abandoned test year (see Exhs. DPU-8-16, Att. 2 (electric); DPU-8-16, Att. 3, Tab 3, at 1-8 (electric); DPU-6-15, Att. 2, at 1 (gas); DPU-6-15, Att. 3, Tab 3, at 1-8 (gas)).

160 The Company does not seek recovery for any costs relating to its decoupling consultant in the month of December 2009, nor does it seek recovery for any costs relating to its costs studies and revenue requirements consultant in January 2010 (except for the last day of January) (Exhs. DPU-8-16, Att. 3, Tabs 3, 14, 16 (Supp. 1) (electric); DPU-6-15, Att. 3, Tabs 3, 15, 16 (Supp. 1) (gas)).

iii. Costs Associated with Responding to Attorney General Oversight Questions

The Company seeks to include in rate case expense for its electric and gas division various costs associated with responding to information requests issued by the Attorney General (hereinafter “Attorney General Oversight Questions”) pursuant to G.L. c. 12, § 11E (the “Green Communities Act”) (Tr. 11, at 1441). Pursuant to the Green Communities Act, the Attorney General may request that any jurisdictional utility respond to up to 15 information requests per calendar month “regarding any matter related to the rates, charges, tariffs, books or service quality of the company.”[161] Pursuant to this statute, the Attorney General requested

[161] As amended, G.L. c. 12, § 11E(c) (2008) states as follows:

> The [A]ttorney [G]eneral may request, orally or in writing, that any company subject to the jurisdiction of the [D]epartment of [P]ublic [U]tilities or the [D]epartment of [T]elecommunications and [C]able respond to not more than 15 information requests, including subparts, per calendar month regarding any matter related to the rates, charges, tariffs, books or service quality of the company, and the company shall answer these information requests fully and completely in a reasonably prompt manner, not to exceed 30 calendar days from the date of issuance, regarding any issue that is within the jurisdiction of the [D]epartment. Department rules pertaining to the scope of questions and objections to discovery shall apply to any such request and the [D]epartment shall have jurisdiction to rule on any objections or motions to compel. If the company fails to answer the information requests in a reasonably prompt manner, the [A]ttorney [G]eneral may request enforcement of this subsection from the department having jurisdiction over the company.

that the Company produce internal reports and presentations relating to its Winter Storm 2008 recovery efforts (RR-DPU-51). In March and April 2010, the Company engaged outside services for assistance in responding to these questions. Specifically, the Company obtained assistance from the decoupling consultant engaged to work on the instant rate cases, a law firm not related to the instant rate cases, and a courier service engaged to work on the instant rate cases (Exhs. DPU-8-16, Att. 3, Tab 3, at 17-19; Tab 4, at 1-5; Tab 5, at 1-3 (Supp. 1) (electric); DPU 6-15, Att. 3, Tab 3, at 26-28 (Supp. 1) (gas)). Fitchburg submitted invoices supporting these costs in the amount of $1,838 for the electric division and $833 for gas division.

The Company argues that responses to the Attorney General's oversight questions are appropriate for inclusion in rate case expense because they relate to the instant rate cases (RR-AG-18). Further, the Company contends that it engaged legal services to assist it in responding to these questions because it was in the process of preparing its rate case filings and needed the advice of counsel on matters related to the anticipated rate cases (Tr. 11, at 1441).

The fact that the Attorney General sought information possibly related to the subject matter of a rate case that the Company was then preparing, but had not yet filed, does not mean that the expense is a rate case expense. Indeed, G.L. c. 12, § 11E(c) gives the Attorney General broad authority to ask questions of the Company "regarding any matter related to the rates, charges, tariffs, books or service quality of the company," and does not require that the questions relate to a proceeding before the Department. As noted in the preceding section, rate case expense is limited to outside services procured for the preparation and presentation of a petition to increase rates under G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et seq. We find that the costs at issue are not rate case expenses as the Company was required to respond to the Attorney General's oversight questions as part of its ongoing service obligation regardless of whether it intended to file a rate case.[162] Accordingly we disallow decoupling costs in the amounts of $431 for the electric division and $833 for gas division, and we disallow miscellaneous costs in the amounts of $1,407 for the electric division, for a total reduction of $1,838 for the electric division and $833 for gas division.

iv. Miscellaneous

The Company seeks to include miscellaneous costs as rate case expenses in its electric and gas division rates totaling $70,021 and $48,516 respectively (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); Sch. RevReq-7-9 (Supp. 3) (gas)).[163] The Company states that these miscellaneous costs are associated with temporary help, printing, publishing, and courier and other delivery services (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); DPU-8-16, Att. 1 (Supp. 2) (electric); Sch. RevReq-7-9 (Supp. 3) (gas); DPU-6-15, Att. 1 (Supp. 2) (gas)). Neither the Attorney General nor any other party challenges the inclusion of these costs in

162 The costs associated with responses to the Attorney General's oversight questions are already supported by the Company's distribution rates in force in 2010. Further, the regulatory expense approved in this Order includes costs for responding to these types of questions on a going forward basis.

163 These amounts reflect removal of the courier and legal services fees relating to responding to Attorney General oversight questions, which were excluded above (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)).

rates. Nevertheless, the Company bears the burden of demonstrating that these costs were reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 224-225; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by the Company and finds that such invoices are properly itemized (Exhs. DPU-8-16, Att. 3 (Supp. 1) (electric); DPU-8-16, Att. 3 (Supp. 2) (electric); DPU-6-15, Att. 3 (Supp. 1) (electric); DPU-6-15, Att. (Supp. 2)).

We note, however, that the Company incorrectly allocated some costs incurred in 2009 and 2011 equally between the electric and gas divisions rather than in accordance with the appropriate allocation factors in effect for those years.[164] Using the appropriate allocation factors, we find that the Company should have allocated expenses incurred in 2009 as follows: 62.99 percent to the electric division and 37.01 percent to gas division (Exhs. DPU-8-19 (electric); DPU-6-19 (gas)). For expenses incurred in 2011, we find that the Company should

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[164] Specifically, the following invoices were incorrectly allocated: (1) a December 28, 2009 delivery services payment of $211.04; (2) an April 1, 2011 printing services payment of $505.08; (3) an April 30, 2011 printing services payment of $2,450; (4) a January 4, 2011 temporary employee payment of $385; (5) a January 4, 2011 temporary employee payment of $607.50; and (6) a January 4, 2011 temporary employee payment of $461.25 (Exhs. DPU-8-16, Att. 3, Tab 7, at 1; Tab 9, at 24, 26; Tab 11, at 1, 4, 7 (Supp. 1) (electric); DPU-6-15, Att. 3, Tab 7, at 1; Tab 9, at 24, 26; Tab 11, at 1, 4, 7 (Supp. 1) (gas)).

have allocated expenses as follows: 59.57 percent to the electric division and 40.43 percent to the gas division (Exhs. DPU-8-19 (electric); DPU-6-19 (gas)). The Department has reallocated the relevant expenses using the appropriate allocation factors in effect for those years.[165] This results in an increase in the electric division's rate case expense of $443, and a corresponding decrease to the gas division's rate case expense in the same amount.

v. Fees for Rate Case Completion

The Company has included in its rate case expense fees related to completion of the rate proceeding in the amounts of $11,587 for its electric division and $9,189 for its gas division (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)). These include fees for the following items: (1) legal representation; (2) rate design consulting services; and (3) decoupling consulting services (Exhs. DPU-8-16, Att. 1 (Supp. 2) (electric); DPU-6-15, Att. 1 (Supp. 2) (gas)).

The Department's long-standing precedent allows only known and measurable changes to test year expenses to be included as adjustments to cost of service. D.T.E. 10-114, at 237; D.T.E. 03-40, at 161; D.T.E. 02-24/25, at 195; D.T.E. 98-51, at 61-62. Proposed adjustments based on projections or estimates are not known and measurable, and recovery of those expenses is not allowed. D.T.E. 10-114, at 237; D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not preclude the

[165] The Company states that it used the 2008 net revenue allocation factor during 2009 and the 2010 net revenue allocation factor during 2011 (Exhs. DPU-8-19 (electric); DPU-6- 19 (gas)).

recovery of fixed fees for completion of compliance filing work in a rate case, but the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts to complete a case after the record closes and briefs are filed, a company may qualify to recover such expenses. D.T.E. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. We have stated that documented and itemized proof is a prerequisite to recovery. D.T.E. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to the compliance filing. D.T.E. 10-114, at 237; see D.P.U. 10-55, at 338.

For both the rate design consultant and the decoupling consultant, the Company provided invoices including a description of the specific services to be performed, the consultant performing the services, the number of hours to be spent, the method by which the number of hours was determined, the billing rate, and the resulting fixed fee (Exhs. DPU-8-16, Att. 3, Tab 1 at 5, 10 (Supp. 2) (electric); DPU-6-15, Att. 3, Tab 1, at 5, 10 (Supp. 2) (gas)). The Department finds that these costs are reasonable and supported by sufficient evidence.

For legal services, the Company provided the number of attorney and paralegal hours to be spent in the compliance phase (Exhs. DPU-8-16, Att. 3, at Tab 7 (Supp. 2) (electric); DPU-6-15, at Att. 3, at Tab 7 (Supp. 2) (gas)). The Company's legal counsel based the number of hours on prior bills from a similar rate case, and calculated the total fee for the compliance phase using the hourly rates charged for the instant proceedings (Exhs. DPU-8-16, Att. 3, at Tab 7 (Supp. 2) (electric); DPU-6-15, Att. 3, at Tab 7 (Supp. 2) (gas)). In order to contain expenses, the law firm further discounted the total fee for the compliance phase (Exhs. DPU-8-16, Att. 3, at Tab 7 (Supp. 2) (electric); DPU-6-15, Att. 3, at Tab 7 (Supp. 2) (gas)). The Department finds that these costs are reasonable and supported by sufficient evidence.

e. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expenses so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 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.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

The Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four rate cases, including the present case, rounded to the nearest whole number. D.P.U. 10-55, at 339; D.T.E. 05- 27, at 163 n. 105; D.T.E. 03-40, at 164 n. 77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

The Company proposes a four-year rate case expense normalization period for each division (Exhs. Unitil-MHC-1, at 41 (electric); Unitil-MHC-1, at 30 (gas)). The record reveals that the average interval between the Company's last four rate cases for its electric division is 3.68 years (Exh. Sch. RevReq-7-9 n.1 (Supp. 3) (electric)).[166] The average interval between the Company's last four rate cases for its gas division is 4.22 years (Exh. Sch. RevReq-7-9 n. 1 (Supp. 3) (gas)).[167] Accordingly, the Department concludes that the appropriate normalization period for Fitchburg's electric and gas divisions is four years.

166 In addition to the current filing, these electric rate case filings were: D.P.U. 07-71, D.T.E. 02-24/25, and D.T.E. 99-118 (Exh. Sch. RevReq-7-9 n. 1 (Supp. 3) (electric)).

167 In addition to the current filing, these gas rate case filings were: D.T.E. 06-109, D.T.E. 02-24/25, and D.T.E. 98-51 (Exh. Sch. RevReq-7-9 n. 1 (Supp. 3) (gas)).

4. Requirement to Control Rate Case Expense

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 yet again, 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. 10-55, at 341; 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.

As we have in the sections above, 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. See D.P.U. 10-55, at 343. 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. See D.P.U. 10-55, at 343.

There are clear benefits to shareholders from approval of rate increases and, therefore, the Department has found that it may be appropriate for shareholders to shoulder a portion of the expense. See D.P.U. 10-55, at 343-344; D.P.U. 10- 70, at 166; D.P.U. 08-35, at 135. As one means to demonstrate that rate case expense has been contained, the Department has directed all 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. In this case, Fitchburg stated that it has “considered” the issues raised in the Department’s Orders regarding rate case expense and has determined that the Company's shareholders "are already bearing a portion of rate case expense under the Department's existing ratemaking practice" (Exh. DPU-8-20 (electric)).

We consider the Company's response to our directive to be inadequate. The Department was aware of our ratemaking precedent at the time we gave the direction to companies to consider some sharing of expenses with shareholders as a means of containing rate case expense. We clarify here that, as an important means of demonstrating that rate case expense has been contained, all gas and electric companies in future rate case filings are required to demonstrate that, at a minimum, they fully considered meaningful proposals for some portion of the rate case expense to be borne by shareholders as a departure from the Department's current ratemaking practice. The companies are required to document such analysis in their direct case and adequately justify any decision not to adopt such proposals.

5. Conclusion

Fitchburg has proposed a rate case expense for its electric division of $1,010,811 and a rate case expense for its gas division of $665,537, for a total rate case expense of $1,676,348 (Exhs. Sch. RevReq-7-9 (Supp. 3) (electric); Sch. RevReq-7-9 (Supp. 3) (gas)). The Department has made the following reductions to the electric division's proposed rate case expense: (1) $45,269 associated with the vegetation management consultant; (2) $58,841 associated with the storm cost recovery consultant; (3) $13,617 associated with the difference between the selected decoupling consultant and a lower bid; (4) $31,507 associated with decoupling services in connection with D.P.U. 07-50; (5) $688 associated with valet parking and upgraded flights; (6) $15,269 associated with the rate design consultant's work on an abandoned test year; (7) $12,357 associated with the rate design consultant's subcontractor's work on an abandoned test year; and (8) $1,838 associated with work on Attorney General's oversight questions. Further, the Department has offset these reductions with an addition of $443 to account for costs improperly allocated to the gas division. These adjustments result in a total disallowance of $178,943 in proposed rate case expense for the electric division, which produces an allowable rate case expense of $831,868 for the electric division.

The Department has made the following reductions to the gas division's proposed rate cast expense: (1) $9,241 associated with the difference between the selected decoupling consultant and a lower bid; (2) $21,661 associated with decoupling services in connection with D.P.U. 07-50; (3) $492 associated with valet parking and upgraded flights; (4) $10,420 associated with the rate design consultant's work on an abandoned test year; (5) $6,361 associated with the rate design consultant's subcontractor's work on an abandoned test year; (6) $833 associated with work on Attorney General oversight questions; and (7) $443 to account for costs that should have been allocated to the electric division. These adjustments result in a total disallowance of $49,451 in proposed rate case expense for the gas division, which produces an allowable rate case expense of $616,086 for the gas division.

Based on these findings, the Department concludes that the correct level of normalized rate case expense for the electric division is $207,967 ($831,868 divided by four years).

The Company booked to the electric division $172,917 in test year rate case expense (Exhs. Unitil-MHC-1, at 41 (electric); Sch. RevReq-7-9 (Supp. 3) (electric)). The Company proposed to increase its cost of service by $79,786 (Exh. Sch. RevReq-7-9 (Supp. 3) (electric)). Accordingly, the Department will reduce Fitchburg's proposed cost of service for the electric division by $44,736 to reflect the annual level of normalized rate case expense of $207,967.

Based on these findings, the Department concludes that the correct level of normalized rate case expense for the gas division is $154,021 ($616,086 divided by four years). The Company booked to the gas division $213,600 in test year rate case expense (Exhs. Unitil-MHC-1, at 30-31 (gas); Sch. RevReq-7-9 (Supp. 3) (gas)). The Company proposed to decrease its cost of service by $47,216 (Exh. Sch. RevReq-7-9 (Supp. 3) (gas)). Accordingly, the Department will reduce Fitchburg's proposed cost of service for the gas division by an additional $12,363 to reflect the annual level of normalized rate case expense of $154,021.

Finally, we note that the Company's schedules incorrectly present rate case expense as part of its depreciation and amortization expense (Exhs. Sch. RevReq-7 (Supp. 3) (electric); Sch. RevReq-7 (Supp. 3) (gas)). Instead, the Company should have presented rate case expense as part of its O&M expense. See e.g., D.P.U. 10-55 (analyzing rate case expense as part of O&M expenses); D.P.U. 10-114 (same). Therefore, the Department has removed rate case expense from the attached Schedule 3 and had added this expense as a new line item in Schedule 2 of this Order.

D. Attorney General's Consultant Costs

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).

The Department authorized the Attorney General to expend up to $250,000 for outside experts and consultants with respect to the Company's electric division petition. Fitchburg Gas and Electric Light Company, D.P.U. 11-01, Order on Attorney General's Notice of Retention of Experts and Consultants at 5 (February 24, 2011). The Department authorized the Attorney General to expend up to $150,000 for outside experts and consultants with respect to the Company's gas division petition. Fitchburg Gas and Electric Light Company, D.P.U. 11-02, Order on Attorney General's Notice of Retention of Experts and

Consultants at 5 (February 24, 2011). [168] As of June 16, 2011, Fitchburg reports that the Attorney General's experts and consultants expense totaled $179,963.19 for the electric division and $98,997.60 for the gas division (Exhs. DPU-8-18, Att. 2 (Supp. 2) (electric); DPU-6-17, Att. 2 (Supp. 2) (gas)).

2. Fitchburg's Proposed Recovery Mechanisms

Fitchburg proposes to recover its actual Attorney General's consultant expenses ("AGCE") through fully-reconciling mechanisms for each division (Exhs. DPU-8-17 (electric); DPU-6-16 (gas); RR-DPU-67, Att. 1, at 102-103 (proposed M.D.P.U. No. 204, Sheets 1-2); RR-DPU-67, Att. 3, at 161-163 (proposed M.D.P.U. No. 161, Sheets 1-3)). The proposed electric division tariff provides for the recovery of AGCE through a factor in the distribution charge (RR-DPU-67, Att. 1, at 102-103 (proposed M.D.P.U. No. 204, Sheets 1-2)). The Company proposes to recover the AGCE through a uniform cents-per-kWh charge based on the estimated kWh deliveries to "firm customers" over a twelve-month period (RR-DPU-67, Att. 1, at 102-103 (proposed M.D.P.U. No. 204, Sheets 1-2)). The proposed tariff provides for the submission of an annual ACGE factor filing 45 days prior to the date on which a new AGCE factor is to be effective (RR-DPU-67, Att. 1, at 103 (proposed M.D.P.U. No. 204,

[168] In authorizing the Attorney General to expend up to $250,000 and $150,000 for outside experts and consultants in these proceedings, the Department did not address the mechanism by which the Company may recover the costs associated with the Attorney General's experts or consultants, stating that this issue would be addressed during the course of the instant rate proceedings. D.P.U. 11-01, Order on Attorney General's Notice of Retention of Experts and Consultants at 5 (February 24, 2011); D.P.U. 11-02, Order on Attorney General's Notice of Retention of Experts and Consultants at 5 (February 24, 2011)

Sheet 2)). The proposed tariff also includes a reconciliation adjustment for the amount of over- or under-collection of the prior year's AGCE (RR-DPU-67, Att. 1, at 103 (proposed M.D.P.U. No. 204, Sheet 2)).[169]

The Company's proposed gas division tariff provides for the recovery of AGCE through a factor in its Local Distribution Adjustment Clause ("LDAC") (RR-DPU-67, Att. 3, at 161-162 (proposed M.D.P.U. No. 161, Sheets 1-2)). The factor is designed to recover AGCE from all firm customers based on forecasted annual throughput (RR-DPU-67, Att. 3, at 161-162 (proposed M.D.P.U. No. 161, Sheets 1-2)). The proposed tariff provides for the submission of an annual ACGE factor filing on September 15th of each year for a November 1st effective date, unless otherwise ordered by the Department (RR-DPU-67, Att. 3, at 161, 162 (proposed M.D.P.U. No. 161, Sheets 1, 2)). The proposed tariff also includes a reconciliation adjustment for the amount of over- or under-collection of the prior year's AGCE (RR-DPU-67, Att. 3, at 162 (proposed M.D.P.U. 161, Sheet 2)).[170]

169 The electric reconciliation adjustment is calculated based on the accumulated difference between actual revenues collected toward the AGCE and the allowed AGCE amount, plus interest calculated on the average monthly balance using the prime rate added to each end-of-month balance (RR-DPU-67, Att. 1, at 103 (proposed M.D.P.U. No. 204)).

170 The gas reconciliation adjustment is calculated based on the accumulated difference between actual revenues received by the Company through application of the AGCE factor to customer bills and the allowed AGCE, plus interest calculated on the average monthly balance using the prime rate added to each end-of-month balance (RR-DPU-67, Att. 3, at 162 (proposed M.D.P.U. No. 161, Sheet 2)).

3. Analysis and Findings

General Laws c. 12, § 11E(b), provides 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. Fitchburg's proposed recovery mechanisms achieve this result.[171] Further, the Company's proposals allow Fitchburg to recover, on a fully reconciling basis, AGCE costs that are distribution-related but, because actual costs are to be recovered, are more appropriately collected outside of base rates. See D.P.U. 10-114, at 280-81; D.P.U. 10-70, at 161; D.P.U. 10-55, at 426; D.P.U. 09-39, at 302.

With respect to the electric division, a reconciling mechanism ensures that ratepayers pay only for costs that are actually incurred, which we find is appropriate under these circumstances.[172] See D.P.U. 10-55, at 426; D.P.U. 09-39, at 302. Additionally, the proposed electric division tariff provides for the AGCE to be collected from all customers (RR-DPU-67, Att. 1, at 102 (proposed M.D.P.U. No. 204, Sheet 1)).[173] Also, the Company's

171 The Department has previously approved the recovery of the ACGE through a reconciling mechanism. See, e.g., D.P.U. 10-114, at 280-281; D.P.U. 10-70, at 161; D.P.U. 10-55, at 426; D.P.U. 09-39, at 302-303; D.P.U. 09-30, at 408.

172 As we gain more experience with these types of expenses, we may consider whether these expenses are better recovered through base rates instead of in a reconciling mechanism. D.P.U. 10-70, at 161; D.P.U. 10-55, at 426 n. 273.

173 We note that Section 1.02 of proposed M.D.P.U No. 204 states that the AGCE "shall be applicable to all firm electricity, as measured in [kWh]. . . delivered by the Company unless otherwise designated" (RR-DPU-67, Att. 1, at 102 (proposed M.D.P.U. No. 204, Sheet 1)). It appears that this is a typographical error as electric customers, unlike gas customers, are not generally described as "firm." As part of the Company's compliance filing co to this Order, Fitchburg is directed to remove the "firm" from this tariff.

proposal to include interest using the prime rate computed in accordance with 220 C.M.R. § 6.08(2) is consistent with previous AGCE tariffs approved by the Department. See D.P.U. 10-114, at 279-281; D.P.U. 10-55, at 425-426. Accordingly, we conclude that Fitchburg's proposal to recover the AGCE through its distribution rates is reasonable and appropriate and, therefore, approved.

Similarly, with respect to the gas division, a reconciling mechanism ensures that ratepayers pay only for costs that are actually incurred. The Company's LDAC is applicable to all firm gas customers (i.e., both sales and transportation customers) (RR-DPU-67, Att. 3, at 128 (proposed M.D.P.U. No. 145, Sheet 2)). In addition, the Company's proposal to include interest using the prime rate calculated in accordance with 220 C.M.R. § 6.08(2) is consistent with the interest rate applied to unrecovered balances for all other LDAC reconciliation mechanisms as well as previous AGCE tariffs approved by the Department (see RR-DPU-67, Att. 3 (proposed M.D.P.U. No. 161)); D.P.U. 10-114, at 279-281). Accordingly, we conclude that Fitchburg's proposal to recover the AGCE through its LDAC is reasonable and appropriate and, therefore, approved.

With respect to both proposed tariffs, for reasons of administrative efficiency, we find that separate annual AGCE reconciliation filings are not warranted. Accordingly, the Department directs the Company to include its electric AGCE factor filing as part of its annual electric division reconciliation filing. See D.P.U. 10-70, at 161. Similarly, the Department directs the Company to include its gas AGCE factor filing as part of its annual gas division LDAC filing. As part of its compliance filing to this Order, the Department directs the Company to include language in the appropriate tariffs specifying where such filings will be made.

E. Property Taxes

1. Introduction

During the test year, Fitchburg booked $970,369 in property taxes to its electric division and $778,969 in property taxes to its gas division, for a total property tax expense of $1,749,338 (Exhs. Sch. RevReq-6 (Supp. 3) (electric); Sch. RevReq-6 (Supp. 3) (gas); Sch. RevReq-7-12 (Supp. 3) (electric); Sch. RevReq-7-12 (Supp. 3) (gas)). The Company proposes to increase its electric division test year cost of service by $242,776 related to property taxes, of which $21,912 will be assigned to internal transmission[174] (Exh. Sch. RevReq-7-12 (Supp. 3) (electric)). Fitchburg also proposes to increase its gas division test year cost of service by $160,359 related to property taxes (Exh. Sch. RevReq-7-12 (Supp. 3) (gas)). The proposed adjustments produce a company-wide increase in base distribution rates of $381,223.

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[174] In determining the proportional assignment of property taxes to internal transmission, the Company took its total transmission-related plant in service of $9,573,438 as a percent of its total electric-related plant in service of $106,069,221 to calculate a plant allocation factor of 9.0257 percent (Exh. WP-RevReq-3-3 (electric); Tr. 11, at 1419-1420).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department's policy is to base property tax expense on the most recent property tax bills and that the Company acknowledges this precedent (Attorney General Brief at 66, citing Exh. Unitil-MHC-Rebuttal-2, at 10-11). Thus, the Attorney General contends that the Company's pro forma property tax expense must be supported by actual tax bills and not include any estimate of property tax expense (Attorney General Brief at 66, citing Exhs. AG-DJE-1, at 10 (electric); AG-DJE-1, at 12 (gas)).

b. Fitchburg

The Company asserts that its submission of actual updated property tax bills reflects known and measureable changes to the test year amount of property tax expense and, therefore, that its proposed adjustments related to property taxes should be included in the cost of service (Company Brief at 59). The Company states that its initial submission of estimated tax expense, using a three percent escalator, was a placeholder that was replaced upon the receipt of actual updated property tax bills (Company Brief at 59).

3. Analysis and Findings

The Department's general policy is to base property tax expense 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 108-109; D.P.U. 86-280-A at 7, 17; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). The Department has rejected the use of projected data to determine a company's municipal tax expenses. D.P.U. 09-39, at 244; D.P.U. 08-35, at 150; D.P.U. 95-50 (Phase I) at 109-110.

In its initial submission of property tax expense, the Company provided a partial set of tax bills and then escalated its total expense for both the electric and gas divisions by three percent to represent an estimate of the increase in property taxes expected to occur during the course of these proceedings (Exhs. Unitil-MHC-1, at 38 (electric); Unitil-MHC-1, at 28 (gas); Sch. RevReq-7-12 (electric); Sch. RevReq-7-12 (gas); AG-3-19 (electric); AG-8-33, Att. (gas); Tr. 7, at 774-775). However, the Company noted that, in subsequent filings it would supplement its proposed property tax adjustment with actual tax bills (Exhs. Unitil-MHC-1, at 38 (electric); Unitil-MHC-1, at 28 (gas)).

The Company's final property tax expense adjustments are based on actual tax bills received for fiscal tax year 2010/2011 (Exhs. Sch. RevReq-7-12 (Supp. 3) (electric); Sch. RevReq-7-12 (Supp. 3) (gas)). In deriving the proposed adjustments, the Company determined the overall amount of property tax expense based on the current tax bills, removed a portion of the overall amount for land held for future use, and then allocated 56.36 percent of the remaining expense to its electric division, and 43.64 percent to its gas division (Exhs. Sch. RevReq-7-12 (Supp. 3) (electric); Sch. RevReq-7-12 (Supp. 3) (gas)). The Company also removed from the property tax expense allocated to the electric division a portion to be assigned to internal transmission. (Exh. Sch. RevReq-7-12 (Supp. 3) (electric)). In these updated submissions, the Company did not estimate any amount of property tax expense (Exhs. Sch. RevReq-7-12 (Supp. 3) (electric); Sch. RevReq-7-12 (Supp. 3) (gas)).

The Company's revised calculations are consistent with the Department precedent as they are based on actual property tax bills. Further, we have reviewed the property tax bills submitted by Fitchburg and find that they support the overall property tax expense reported by the Company (Exhs. AG-3-18, Att. (electric); AG-3-18, Att. (Supp.) (electric)). Therefore, the Department accepts the Company's proposed adjustments.[175] Accordingly, the Department will increase the Company's electric division cost of service by $220,864 and increase the Company's gas division cost of service by $160,359.

F. Depreciation Expense

1. Introduction

During the test year, Fitchburg booked $3,461,408 in depreciation expense for its gas division and $4,731,130 for its electric division; of this latter amount, $356,203 was assigned to internal transmission and $4,374,927 was assigned to base distribution (Exhs. Sch. RevReq-7-13 (Supp. 3) (gas); Sch. RevReq-7-13, at 4 (Supp. 3) (electric)). The Company proposes to decrease its gas division depreciation expense by $34,237 to $3,427,171

[175] The Department notes that these adjustments are being made net of property taxes capitalized by the Company in the amounts of $10,224 for the electric division and $8,208 for the gas division (Exhs. Sch. RevReq-6 (Supp. 3) (electric); Sch. RevReq-6 (Supp. 3) (gas)). In addition, the adjustments being made by the Company are also net of internal transmission in the amount of $86,660 for the electric division (Exhs. Sch. RevReq-6 (Supp. 3) (electric)).

(Exh. Sch. RevReq-7-13 (Supp. 3) (gas)). The Company also proposes to decrease its total electric division depreciation expense by $51,425 to $4,679,705 (Exh. Sch. RevReq-7-13, at 1 (Supp. 3) (electric)). Because Fitchburg assigns $367,488 to internal transmission, the proposed base distribution depreciation expense is $4,312,218, representing a net decrease to distribution-related depreciation expense of $62,709 (Exh. Sch. RevReq-7-13, at 4 (Supp. 3) (electric)).

For its gas division, Fitchburg applied account-specific accrual rates to test year-end depreciable plant, resulting in a 2.83 percent composite accrual rate for manufactured gas plant, a 4.46 percent composite accrual rate for distribution plant, and a 4.36 percent composite accrual rate for general plant (Exh. Sch. PMN-2, sch. C (gas)). For its electric division, the Company applied account-specific accrual rates to test year-end depreciable plant, resulting in a 4.20 percent composite accrual rate for transmission plant, a 4.69 percent composite accrual rate for distribution plant, and a 4.67 percent composite accrual rate for general plant (Exh. Sch. PMN-2, sch. A at 1, 2 (electric)). For common plant used by both the gas and electric divisions, the Company applied account-specific accrual rates, resulting in an overall accrual rate of 5.83 percent (Exhs. Sch. PMN-2, sch. E (gas); Sch. PMN-2, sch. E (electric)). These accrual rates represent a decrease from the Company’s current overall accrual rates of 4.56 percent for gas plant, 4.79 percent for electric plant, and 7.20 percent for common plant (Exhs. Sch. PMN-2, schs. B, D, F (gas); Sch. PMN-2, schs. B, D, F (electric)).

In support of its proposed accrual rates, the Company presented a depreciation study using plant data as of December 31, 2008, and employing the overall straight line method, broad group procedure, and average remaining life technique to estimate the proposed depreciation accrual rates (Exhs. Unitil-PMN-3, at 3 (gas); Unitil-PMN-3, at 3 (electric); Sch. PMN-2, sch. C (gas); Sch. PMN-2, sch. A (electric)). The Company's historic life analysis relied on the simulated plant record balances ("SPR-BAL") method, a well known and accepted method employed in depreciation analysis (Exhs. Unitil-PMN-3, at 6 (gas); Unitil-PMN-3, at 6 (electric)). The SPR-BAL analysis is an iterative procedure in which factors derived from empirical survivor curves are applied to actual recorded annual plant additions to generate theoretical surviving year-end balances (Exhs. Unitil-PMN-3, at 6 (gas); Unitil-PMN-3, at 6 (electric)). In this way, empirical curves that best simulate the actual ending balances in a specified range of years are determined to establish an appropriate average service life ("ASL") for the respective plant accounts (Exhs. Unitil-PMN-3, at 6 (gas); Unitil-PMN-3, at 6 (electric)).[176]

[176] These empirical curves are generally known as "Iowa curves" (Exh. Unitil-PMN-3, at 7). Iowa curves were initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s, and are widely accepted in determining average life frequencies for utility plant. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). Initially, 18 curve types were published in 1935, and four additional survivor curves were identified in 1957. D.T.E. 06-40, at 66-67 n.44.

2. Positions of the Parties

a. Attorney General

The Attorney General notes that Fitchburg is proposing to increase its depreciation accrual rate for electric meters from 1.88 percent to 10.13 percent (an increase of more than 500 percent); however, she argues that Fitchburg has provided no evidence to support its proposal (Attorney General Brief at 77; Attorney General Reply Brief at 31-32). According to the Attorney General, the proposed increase in the depreciation accrual rate for electric meters is inconsistent with the concept of rate continuity and fails to recognize the concept of gradualism in changing depreciation accrual rates (Attorney General Brief at 77). She argues that although Fitchburg recognized the need for gradualism for other plant accounts, the Company disregards any such notion in determining the ASL and depreciation accrual life for electric meters (Attorney General Brief at 77-78, citing Exh. Sch. PMN-2, at 29-31 (electric)).

Moreover, the Attorney General claims that the Company's depreciation study is inconsistent on the treatment of gas meters versus electric meters (Attorney General Brief at 78; Attorney General Reply Brief at 32). The Attorney General notes that while Fitchburg proposes an ASL of 20 years for the new advanced metering infrastructure ("AMI") enabled electric meters, the Company recommends an ASL of 33 years for the new AMI-enabled gas meters (Attorney General Brief at 78, citing Exhs. Sch. PMN-2, at 37 (gas); Sch. PMN-2, at 31 (electric)). The Attorney General argues that Fitchburg has failed to address this inconsistency in service lives (Attorney General Brief at 78).

Finally, the Attorney General submits that the Company's depreciation study fails to demonstrate an understanding of the nature of the new meters because the study appears to conclude that new electric meters will not be durable (Attorney General Brief at 78, citing Exh. Sch. PMN-2, at 31 (electric)). Instead, the Attorney General argues that the Company itself acknowledged that the new meters are fundamentally identical to the old meters, with the exception of electronic modules to provide for remote meter reading (Attorney General Brief at 78, citing Tr. 18, at 2506-2507; Attorney General Reply Brief at 32). On this basis, she concludes that there is no reason why the new electric meters will have a shorter life than the old electric meters (Attorney General Brief at 78; Attorney General Reply Brief at 32).

b. Fitchburg

The Company states that the new depreciation rates it developed and applied to test year-end depreciable plant balances result in lower depreciation rates (Company Brief at 57). Fitchburg notes that the proposed depreciation accrual rates result in a net decrease to cost of service of $62,709 for its electric division and a net decrease to cost of service of $34,237 for its gas division (Company Brief at 57, citing Exhs. Unitil-MHC-1, at 40 (electric); Unitil-MHC-1, at 29 (gas); Sch. RevReq-7-13 (Supp. 2) (electric); Sch. RevReq-7-13 (Supp. 2) (gas)).

Regarding the Attorney General's recommended depreciation accrual rate for electric meters, the Company argues that the Department should not accept the Attorney General's recommendation because the ASL of these meters is decreasing (Company Brief at 72;

Company Reply Brief at 39). The Company states that technological advances are the cause of this shorter service life and that, based on the industry-wide average, the new electric meters have an ASL of about 15 to 20 years (Company Brief at 72-73; Company Reply Brief at 39). Moreover, the Company argues that it has replaced all of its old meters without seeking any accelerated treatment of recovery of costs associated with the conversion from the older meters to the more efficient electronic meters (Company Brief at 73). For these reasons, Fitchburg urges the Department to accept the Company's proposed depreciation accrual rate for Account 370 (Company Brief at 73; Company Reply Brief at 39).

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. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1973). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study that is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[177] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A, at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing, and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of statistical analyses but will consider other expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase One) at 54-55. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

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[177] This is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; Boston Edison Company, D.P.U. 1350, at 109-110 (1983).

b. Application of 2008 Study

The purpose of a depreciation study is to develop accrual rates that are then applied to plant balances. It is not inconsistent to apply the accrual rates developed from a plant balance as of a specific date to those plant balances in service on a different date, provided there are no significant changes in plant composition in the intervening period. D.P.U. 08-35, at 145; D.P.U. 92-250, at 70. The Department finds the changes in the composition of Fitchburg's plant between December 31, 2008, and December 31, 2009, do not materially affect the validity of the depreciation study's accrual rates. Thus, we find that it is appropriate to apply the results of this depreciation study with appropriate revisions to test year-end plant.

c. Account-By-Account Analysis

i. Introduction

The parties in this proceeding have contested only one of Fitchburg's proposed accrual rates. Nonetheless, the Department has examined each of the proposed accrual rates submitted in the Company's depreciation study, including the SPR-BAL and cost of removal analyses. The Department finds that the Company's depreciation witness has demonstrated an appropriate knowledge of depreciation concepts and applications and has applied his judgment and expertise in interpreting the data and statistics derived from this data (Exhs. Unitil-PMN-3 (gas); Unitil-PMN-3 (electric); Sch. PMN-2 (gas); Sch. PMN-2 (electric); WPs FG&E-Electric SPR BAL Eval.notes; FG&E-Gas SPR BAL Eval.notes; FG&E-Electric

SAL COR Analysis w-Notes; FG&E-Gas SAL COR Analysis w-Notes; Tr. 3, at 246-249, 253-256). The witness also demonstrated his familiarity with the Company's plant and maintenance practices (Exhs. Unitil-PMN-3 (gas); Unitil-PMN-3 (electric); Sch. PMN-2 (gas); Sch. PMN-2 (electric); WPs FG&E-Electric Info Request with Responses; FG&E-Gas Info Request with Responses; Field Inspection Photos.electric; Field Inspection Photos.gas).

Based on our review, the Department finds that Fitchburg has properly interpreted the results of the statistical analyses in determining the appropriate depreciation accrual rates for those accounts that were not contested by the parties. Our discussion of the proposed accrual rate for Account 370 follows.

ii. Account 370

The current accrual rate for Account 370 is 1.88 percent (Exhs. Sch. PMN-2, at 31 (electric); AG-1-24, Att. (electric)). The Company proposes to replace the current ASL of 45 years and R 4.0 curve with a 20-year ASL and an S 4.0 Iowa curve (Exh. Sch. PMN-2, at 31 (electric)). Additionally, the Company proposes to increase the net salvage for electric meters from zero percent to a negative ten percent, resulting in an accrual rate of 10.13 percent (Exh. Sch. PMN-2, at 31 (electric)). The proposed ASL is based on industry experience with AMI meters (Exh. Sch. PMN-2, at 31 (electric)). The Attorney General opposes any change to the depreciation accrual rate for Account 370 on the grounds that the proposed change violates the concept of gradualism and demonstrates a lack of understanding about AMI meters (Attorney General Brief at 77-78).

The statistical analyses for Account 370 are based on data for the period 1976 through 2008, which consists almost entirely of electromechanical meters that had been replaced with AMI meters by the end of 2007 (Exhs. Sch. PMN-2, at 31 (electric); WP-FG&E-Electric Theo. Reserve, Account 370; RR AG-51). While the SPR-BAL analyses indicate that the best fitting ASLs range between 32.23 years and 37.96 years, the low confidence indices associated with the statistical analyses render the results of SPR-BAL analysis unreliable for determining the ASL for this account (Exhs. WP-FG&E-Electric SPR-BAL Analysis, Account 370; FG&E-Electric SPR-BAL Eval.Notes at 24). Consequently, it is necessary to use other methods to derive the ASL for this account.

In the instant case, Fitchburg determined that the new AMI-enabled meters are anticipated to have shorter lives due to the physical life of the electric components and the occurrence of technological changes (Exh. Sch. PMN-2, at 31 (electric)). While AMI meters may have a shorter life than electromechanical meters, the Company's evidence on this point is confined to a generalized observation that AMI meters have a service life of 15 to 20 years (Exhs. Sch. PMN-2, at 31 (electric); WP-FGE-Electric SPR BAL Eval.Notes at 23-24). Although the Company has demonstrated that a 45-year ASL is not reasonable for this account, we find that it has not demonstrated that a 20-year ASL is appropriate (Exh. WP-FGE-Electric SPR BAL Eval.Notes at 23-24).

The Department has recently approved of the use of 23-year and 25-year ASLs for Account 370. See D.P.U. 10-70, at 136 (ASL of 23 years); D.P.U. 09-39, at 196-197

(ASL of 25 years). Based on the experience of these other companies and the shorter anticipated service lives of AMI meters, tempered by the recognition that the Company has limited actual experience with its AMI meters, the Department finds that an ASL of 25 years is justified for this account.

Application of a 25-year ASL to the Company's S-4.0 curve data increases the remaining life of this account from 15.9 years to 19.9 years (see Exh. Sch. PMN-2, sch. A at 1 (electric)). The Department accepts Fitchburg's proposed salvage factor of negative ten percent as consistent with the results of its salvage analysis and salvage factors approved for other companies to this account (Exh. Unitil-PMN-3, Sch. PMN-2, WP-FG&E-Elec SAL COR Analysis. See also D.P.U. 09-39, at 197. When combined with the negative ten percent salvage factor, the ASL data produces an accrual rate of 8.09 percent for Account 370. Accordingly, the Department directs the Company to apply a depreciation accrual rate of 8.09 percent to Account 370.

d. Conclusion

In order to calculate Fitchburg's annual depreciation expense based on the revised accrual rate for Account 370, the Department has applied the accrual rates approved by this Order to the Company's depreciable plant balances included in rate base. Based on this analysis, the Department finds that the Company's annual depreciation expense is $3,427,171 for its gas division, and $4,303,893 for the base distribution function of its electric division.[178] Accordingly, the Company's proposed gas division depreciation expense is approved, and its proposed electric division expense is reduced by $8,324.

G. Amortization Expense

1. Introduction

During the test year, Fitchburg booked $455,762 in distribution-related amortization expense for its electric division and $397,692 in distribution-related amortization expense for its gas division (Exhs. Sch. RevReq-1, at 2 (Supp. 3) (electric); Sch. RevReq-1, at 2 (Supp. 3) (gas)). These expenses include $112,477 attributable to the amortization of various computer software programs booked to Account 303 (intangible plant) and Account 399 (other intangible plant) for the Company's electric division, and $93,097 attributable to the amortization of computer software booked to Account 303 (intangible plant) and Account 399 (other intangible plant) for the Company's gas division (see Exhs. AG-8-29, Att. 2 (electric); AG-7-17 Att. 2 (gas)).[179] In addition to these expenses, Fitchburg's electric cost of service includes $100,323 in consulting costs it incurred in preparation for its first audit of compliance related to North American Reliability Corporation's ("NERC") new reliability and planning standards (see Tr. 15, at 1869-1873).

[178] Because only transmission and a portion of general plant is assigned to internal transmission plant, no assignment of depreciation expense associated with Account 370 is warranted.

[179] These totals include $17,908 and $12,089 allocated from USC to the Company's electric and gas divisions, respectively, and exclude $10,030 in electric division amortization expense allocated to internal transmission (see Exhs. AG-8-28, Att. 2 (electric); AG 7-17, Att. 2 (gas); WP-RevReq-3-2 (Supp. 3) (electric); WP-RevReq-3-2 (Supp. 3) (gas)).

2. Position of the Parties

a. Attorney General

The Attorney General argues that the Department should reduce Fitchburg's proposed amortization expense for its electric division by $52,000, and reduce the Company's proposed amortization expense for its gas division by $54,000 (Attorney General Brief at 67; citing Exhs. AG-DJE-1, at 11 (electric); AG-DJE-1, at 13 (gas)). According to the Attorney General, a number of software programs will be fully amortized before the midpoint of the rate year and, therefore, should be excluded from cost of service (Attorney General Brief at 66-67, citing Exhs. AG-DJE-1, at 10 (electric); AG-DJE-1, at 13 (gas)). The Attorney General contends that the Company did not dispute that the amortizations in question were expiring nor did it argue that her proposed adjustments were inconsistent with established Department practice (Attorney General Brief at 67; Attorney General Reply Brief at 31).

The Attorney General disputes Fitchburg's argument that there are a number of software system development projects authorized in 2011 that are expected to be completed and in service in 2011 (Attorney General Brief at 67; Attorney General Reply Brief at 31). The Attorney General contends that there is no evidence that the amortization of the new systems will supplant the expiring amortizations and that the Company failed to account for the fact that as the software systems are completed and placed into service amortization will be expiring on other software systems (Attorney General Brief at 67; Attorney General Reply Brief at 31).

According to the Attorney General, failing to adjust test year expenses for expiring amortizations would be inconsistent with Department practice (Attorney General Brief at 67; Attorney General Reply Brief at 31).

With respect to Fitchburg's expenditures related to NERC reliability and planning standards, the Attorney General argues that the Company admits that these expenses booked in the test year will not recur (Attorney General Brief at 62, citing Tr. 15, at 1870). Therefore, the Attorney General argues that these costs are extraordinary, non-recurring expenses and recommends that they be amortized over a three-year period, resulting in a reduction to cost of service in the amount of $66,882 (2/3 of $100,322.55) (Attorney General Brief at 62-63).

b. Fitchburg

The Company claims that its test year computer software amortization expense is reasonable and representative of computer software expense going forward (Company Brief at 71). The Company contends that authorized software system development projects which are expected to be completed in 2011 will replace those systems with expiring amortizations. Accordingly, the Company argues that its year-to-year changes in software costs are normal and reflect changes in technology (Company Brief at 71, citing Exh. Unitil-MHC-Rebuttal-2, at 11).

With respect to the amortization of expenditures related to NERC's new reliability and planning standards, the Company states these expenses represent transmission-related costs (Company Brief at 68, citing WP-RevReq-3-1.1 (electric); Tr. 15, at 1869-1870. Therefore, Fitchburg contends that these costs are not included in its test year distribution expense (Company Brief at 68).

3. 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. 10-55, at 421; 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. While the Department agrees with Fitchburg that it is important to keep its technology platforms current, the Company's test year intangible plant includes a number of applications that had been fully amortized before the test year (Exhs. AG 8-29, Att. 1 (electric); AG 7-17, Att. 1 (gas)). Although the Company contends that it will replace the Power Plant Fixed Asset System and upgrade its CIS system during 2011, the cost and timing of these projects is sufficiently unclear as to render them speculative (Exh. Unitil-MHC-Rebuttal-2, at 11). Thus, the Department will adjust test year amortization expense for known and measurable changes.

An analysis of the Company's test year amortization expense with the remaining unamortized balances as of the end of 2010 indicates that a number of software applications will be fully amortized as of the date of this Order.[180] The Company's expiring electric division software applications include:
(1) Management System of Internal Data MV90

[180] While the Company's Daily Cash Reporting software also was fully amortized by the end of 2009, Fitchburg excluded the associated amortization expense from its proposed cost of service (Exhs. AG-8-29, Att. 1 (gas); AG-7-17, Att. 1 (gas)).

Metering; (2) Milsoft LandBase Graphical Software; (3) GIS; and (4) GIS Asset Management, including an associated late charge (Exh. AG-8-29, Att. 1 (electric)). In addition, as of the end of 2010, there were three months of amortization expense remaining on the Company's Operations Data Integration software (Exh. AG-8-29, Att. 1 (electric)). No new software applications were placed into service for the Company's electric division after the end of the test year (Exh. AG-8-29, Att. 1 (electric)).

The Company's expiring gas division software applications include: (1) Web-ops Gas Data Base System; (2) GIS Asset Management, including an associated late charge; (3) CIS System; and (4) WebOps Development (Exh. AG-7-17, Att. 1 (gas)). As with Fitchburg's electric division, there were three months of gas division amortization expense remaining on the Company's Operations Data Integration software (Exh. AG-7-17, Att. 1 (gas)). Three new software applications were placed into service during 2010, with a total amortization expense during that year of $3,798 (Exh. AG-7-17, Att. 1 (gas)).

Finally, USC's AP Imaging, Interactive Voice Recognition, and Sarbanes ICFR Systems were fully amortized as of the end of 2009 (Exh. AG-7-17, Att. 2 (gas)). Two new software applications, consisting of Power Tax System and Data Privacy, were placed into service during 2010 with a total amortization expense during that year of $31,834 (Exh. AG 7-17, Att. 2 (gas)).

Based on the above analysis, the Department finds that these expiring amortizations and new software applications represent a known and measurable change to test year cost of service. Therefore, the Department will reduce the Company's amortization expense to recognize these software expirations.

The Department will include in the Company's electric division cost of service the software amortization expense for 2010 of $64,513, plus $10,907 in allocated software amortizations from USC, less the following expiring amortizations: (1) $5,657 for the Operation Data Integration software; (2) $1,339 for the Management System of Internal Data MV90 Metering; (3) $311 for the Milsoft LandBase Graphical Software; (4) $5,282 for the CIS System; (5) $410 for the WebOps Development; and (6) $3,044 for the GIS Asset Management, including an associated late charge. This results in a total electric division software amortization expense of $59,377. Of this amount, 9.4361 percent, or $5,603, is assigned to internal transmission, and the remaining $53,774 is assigned to base distribution (see Exh. WP-RevReq-3-2 (Supp. 3) (electric)). The Department will include in the Company's gas division cost of service the software amortization expense for 2010 of $46,826, plus $7,403 in allocated software amortizations from USC, less the following expiring amortizations: (1) $5,605 for the Operation Data Integration software; (2) $5,116 for CIS System; (3) $397 for WebOps Development; (4) $1,500 for the WebOps Data Base System; and (5) $2,742 for the GIS Asset Management, including an associated late charge. This results in a total gas division software amortization expense of $38,869. Accordingly, the Department will reduce the Company's test year electric division cost of service by $58,703 ($112,477 – $53,774), and will reduce the Company's test year gas division cost of service by $54,228 ($93,097 – $38,869).

Regarding the Attorney General's proposal to amortize costs associated with NERC's reliability and planning standards, the record demonstrates that these costs have been assigned to the Company's internal transmission function, and not included in distribution rates (Exh. WP-RevReq-3-1.1 (Supp. 3) (electric); Tr. 15, at 1869-1870). Therefore, the Department finds that no further adjustment is necessary.

H. Inflation Allowance

1. Introduction

Fitchburg proposes an inflation adjustment of $92,385 for its electric division and $76,753 for its gas division (Exhs. Unitil-MHC-1, at 30-31 (electric); Unitil-MHC-1, at 26 (gas); Sch. RevReq-7-6, at 1 (Supp. 3) (electric); Sch. RevReq-7-8, at 1 (Supp. 3) (gas)). In calculating the inflation allowance, the Company used the gross domestic product implicit price deflator ("GDPIPD") (Exhs. Unitil-MHC-1 (electric), at 30; Unitil-MHC-1 (gas), at 26; Sch. RevReq-7-6, at 2-3 (Supp. 3) (electric); Sch. RevReq-7-8, at 2-3 (Supp. 3) (gas)). The Company applied the GDPIPD from the midpoint of the test year to the midpoint of the rate year, which resulted in a 3.69 percent inflation factor (Exhs. Sch. RevReq-7-6, at 2-3 (Supp. 3) (electric); Sch. RevReq-7-8, at 2-3 (Supp. 3) (gas)). The Company multiplied the inflation factor by its residual O&M expenses of $3,000,570 for its electric division and $2,080,024 for its gas division, which produced an inflation adjustment of $110,721 for its electric division and an inflation allowance of $76,753 for its gas division

(Exhs. Sch. RevReq-7-6, at 1 (Supp. 3) (electric); Sch. RevReq-7-8, at 1 (Supp. 3) (gas)). For the Company's electric division, the Company then removed $18,336 allocated to internal transmission to arrive at a base distribution inflation allowance of $92,385 (Exhs. Sch. RevReq-7-6, at 1 (Supp. 3) (electric); WP-RevReq-3-1.1 (Supp. 3); WP-RevReq-3-1.2 (Supp. 3)).

2. Position of the Parties

a. Attorney General

The Attorney General argues that the Company did not remove the proper level of Winter Storm 2008 investigation expense from its inflation allowance (Attorney General Brief at 59). The Attorney General claims that in calculating its residual O&M expense, the Company removed $789,708 in Winter Storm 2008 investigation expense from the residual O&M expense but improperly included $394,854 as proposed amortized expense (Attorney General Brief at 59, citing Exh. Sch. RevReq-7-8 (electric)).

According to the Attorney General, amortization expense should not be subject to an inflation allowance (Attorney General Brief at 59, citing Exh. AG-DJE-1, at 8 (electric)). In this regard, the Attorney General claims that the Company offered inconsistent positions regarding the $394,854 in expense, alternatively claiming it was a normalized amount and an amortized amount, and then asserting that these expenses are not specific to the Winter Storm 2008 investigation, but also include "other regulatory costs that are similar in nature and type" (Attorney General Brief at 59-60, citing Exhs. Unitil-MHC-Rebuttal-2, at 14; Sch. RevReq-7-8 (electric)); Tr. 17, at 2262). Regardless of how these expenses are classified, the Attorney

General argues that the Company has not established that it will incur any other regulatory costs of the same magnitude of the Winter Storm 2008 investigation (Attorney General Brief at 60; Attorney General Reply Brief at 30). As a result, the Attorney General asserts that the full cost of the Winter Storm 2008 investigation incurred in 2009 should be removed from the Company's inflation allowance (Attorney General Brief at 60; Attorney General Reply Brief at 30).

b. Fitchburg

The Company opposes the Attorney General's recommendation to remove the full amount of Winter Storm 2008 investigation costs from its inflation allowance (Company Brief at 67). The Company asserts that the Winter Storm 2008 was an extraordinary event and that the associated investigation consumed an inordinate amount of Company resources over the course of the test year (Company Brief at 67, citing Tr. 17, at 2229-2230). Further, the Company contends that, as a result of this event, the Department established new reporting and compliance requirements and, therefore, the Company will regularly incur regulatory costs needed to comply with the Department's directives in this regard, as well as other new requirements such as decoupling (Company Brief at 67-68, citing Tr. 17, at 2229-2230, 2261-2262). According to the Company, the normalized amount of expense for the Winter Storm 2008 investigation is a representative level for inclusion in the cost of service and is subject to the same inflation effects as other operating expenses of the Company (Company Brief at 68, citing Exh. Unitil-MHC-Rebuttal-2, at 14). Thus, Fitchburg asserts that the normalized amount of Winter Storm 2008 costs should be included in the inflation allowance calculation (Company Brief at 68).

3. Analysis and Findings

a. Introduction

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21. The Department permits utilities to increase their test year residual O&M expense by 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. 95-40, at 64; D.P.U. 92-250, at 297-298.

b. Cost Containment Measures

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. Fitchburg has undertaken a number of efforts to reduce the Company's O&M costs. For health care costs, the Company has raised premium contributions by non-union employees from 17 to 20 percent of the total cost from 2006 to the present (Exh. AG-1-52 (electric)). Union employees have seen their share of health care insurance premiums rise from eleven percent to 20 percent over the same time period (Exh. AG-1-52 (electric)). In addition, co-payments have risen for union employees and employees have been encouraged to opt-out of their Company provided insurance with the offer of two months worth of employer contributions as compensation (Exh. AG-1-52 (electric)). Finally, the Company has switched to a self-insured plan and the Company began offering high-deductible health plans with Health Savings Account availability (Exh. AG-1-52 (electric)).

In addition to attempts at controlling health care costs, the Company has closed its defined-benefit pension plan to new hires and replaced it with an "Enhanced 401(k) Plan" that is less expensive overall than the defined-benefit pension plan (Exh. AG-9-21 (electric), citing Unitil-GEL-1, at 2 (electric)). Finally, the Company used a compensation study to review the level and competitiveness of its base salaries, salary ranges, and compensation programs relative to those in external markets. The study found that Fitchburg's compensation programs were at the median of the range for most job positions (Exh. AG-9-21 (electric), citing Unitil-GEL-1, at 6-8 (electric)). Based on the results of the report, the Company instituted a pay freeze for its non-union employees (Exh. Unitil-GEL-1, at 8). Based on these facts, we find that Fitchburg has implemented cost containment measures.

c. Winter Storm 2008 Investigation Costs

Fitchburg proposes to include in the inflation allowance the normalized amount of Winter Storm 2008 investigation costs as a representative amount of regulatory costs that purportedly will be incurred in the future (Tr. 17, at 2228-2230, 2262). More specifically, Fitchburg contends that the Company will regularly incur regulatory costs needed to comply with (1) new reporting and compliance requirements established by the Department; and (2) decoupling compliance filing requirements (Company Brief at 67-68, citing Tr. 17, at 2229-2230). Fitchburg asserts that it should be allowed to include the normalized amount of expense for the Winter Storm 2008 investigation in the inflation allowance because the expense is a representative level of the costs associated with these future activities and is subject to the same inflation effects as other operating expenses of the Company. We disagree.

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 (2002); Blackstone Gas Company, D.P.U. 01-50, at 19 (2002); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). As noted above in Section V, the Department has disallowed recovery of the Winter Storm 2008 investigation costs. For this reason alone, the entire expense is subject to removal from the inflation allowance.

However, the Department also will remove from the residual O&M expense those expenses that are significant enough in size to warrant specific focus and effort in adjusting, even if the company did not propose an adjustment for the item. D.P.U. 1720, at 20-21; Western Massachusetts Electric Company, D.P.U. 1300, at 73-84 (1983). It is indisputable that the Winter Storm 2008 investigation costs were significant enough to warrant special focus, as evidenced by Fitchburg's own initial filing.

Further, in order for items to be eligible for an inflation allowance, it stands to reason that they must be representative of the costs that a company will be incurring in the period between the conclusion of the current rate case and that company's next rate case. Here, the Company proposes to use nearly $400,000 of costs from the Winter Storm 2008 as a proxy for future costs that it asserts will be incurred in other, non-storm related regulatory reporting and compliance activities (Tr. 17, at 2230-2231, 2262). However, the Company failed to demonstrate by convincing evidence that the level of spending on regulatory reporting and compliance activities will be similar to the amount of Winter Storm 2008 costs that it seeks to include in the inflation allowance. It is simply not enough for the Company to argue that because it incurred costs in the test year responding to the Winter Storm 2008 investigation it will incur the same level of costs in the future responding to other regulatory reporting and compliance regulations. Fitchburg had ample opportunity to demonstrate that it would incur a known and measureable change to its regulatory reporting and compliance costs beyond the test year and it failed to do so.

Based on these considerations, we disallow the Company's request to include $394,854 in costs related to the Winter Storm 2008 investigation in the inflation allowance. Accordingly, the Department will exclude this amount from the residual O&M subject to inflation allowance.

d. Conclusion

Based on the above findings, the Department concludes that an inflation allowance adjustment equal to the most recent forecast of GDPIPD from the midpoint of the test year to the midpoint of the rate year, applied to the Company's approved level of residual O&M expense less the Department's adjustments, is proper in this case. As shown on Table 1, the resulting inflation allowance for Fitchburg's electric division is $64,784, while the resulting inflation allowance for Fitchburg's gas division as shown on Table 2 is $67,334. Accordingly, the Department will reduce the Company's proposed cost of service by $27,601 for the electric division and reduce the Company's proposed cost of service by $9,419 for the gas division.

Table 1: Inflation Allowance, Electric Division	
Test Year O&M Expense per Books	10,728,146
Less Normalizing Adjustments:	
Payroll	2,921,473
Medical & Dental Insurance	457,335
Property & Liability Insurance	217,124
401(k) Costs	79,917
Management Audit Costs	1,000,000
Sales for Resale	1,018,657
2008 Ice Storm Investigation Adjustment	789,708
Subtotal	6,484,214
Less: Non-Inflationary Items	
Pension	46,580
PBOPs	430,072
Bad Debt	521,318
Amortizations – USC Charge	14,429
Facility Leases – USC Charge	217,868
Equipment Leases	13,095
Subtotal	1,243,362
Residual O&M Expense per Company	3,000,570
Less: Department Adjustments	
Shareholder Services	48,150
Rate Case Expense	172,917
D.P.U. 09-09 Consulting Costs	118,535
Employee Reimbursements	13,543
2008 Ice Storm Investigation Adjustment	394,854
Subtotal	747,999
Projected Inflation Rate from Midpoint of Test Year to Midpoint of Rate Year	3.69%
Inflation Allowance per Company	110,721
Inflation Allowance per DPU	83,120
Assigned to Internal Transmission	18,336
Actual Inflation Allowance	64,784
Reduction to Cost of Service	27,601

Table 2: Inflation Allowance, Gas Division	
Test Year O&M Expense per Books	11,502,270
Less Normalizing Adjustments:	
Payroll	3,096,943
Medical & Dental Insurance	471,076
Property & Liability Insurance	152,828
401(k) Costs	66,431
Gas Refund Charge	4,954,787
Subtotal	8,742,065
Less Non-Inflationary Items:	
Bad Debt	514,532
Amortizations – USC Charge	9,740
Fixed Leases – USC Charge	147,070
Equipment Leases	8,840
Subtotal	680,182
Residual O&M Expense Subject to Inflation per Company	2,080,023
Less: Department Adjustments	
Shareholder Services	32,504
Employee Reimbursements	9,142
Rate Case Expense	213,600
Subtotal	255,246
Projected Inflation Rate from Midpoint of Test Year to Midpoint of Rate Year	3.69%
Inflation Allowance per Company	76,753
Inflation Allowance per DPU	67,334
Reduction to Cost of Service	9,419

I. Shareholder Services

1. Introduction

The Company reports that, during the test year, USC incurred $280,244 in shareholder services expense, of which $80,654 (28.78 percent) was allocated to Fitchburg (Exh. AG-8-28 (electric)).[181] Of the amount allocated to Fitchburg, the Company further allocated $48,150 (59.70 percent) to its electric division and $32,504 (40.30 percent) to its gas division (Exh. AG-8-28 (electric)).

The test year costs incurred by USC are for three categories of shareholder services expenses (Exh. Unitil-MHC-Rebuttal-2, at 8; Tr. 11, at 1500-1502; RR-DPU-58, Att.). The first category, "SEC and Compliance," consists of $107,342 in Securities and Exchange Commission ("SEC") and other regulation compliance costs related to annual financial filings (Exh. Unitil-MHC-Rebuttal-2, at 8; Tr. 11, at 1501; RR-DPU-58, Att.). The second category, "Annual Reporting," consists of $50,106 in costs related to providing investors with annual reporting and financial information in order for the Company to access equity and debt from capital markets (Exh. Unitil-MHC-Rebuttal-2, at 9; Tr. 11, at 1501; RR-DPU-58, Att.). The third category, "Shareholder Direct," consists of $122,797 in costs and expenses that are associated with the direct servicing of current shareholder plans and programs

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181 The Company initially reported that USC's shareholder services expense totaled $267,129, (Exhs. AG 1-76 (electric); AG 1-76 (gas); Tr. 7, at 763). However, after reviewing this discrepancy between documentation, the Company stated that exhibits supporting expenses in the amount of $280,244 were more accurate (Tr. 11, at 1500-1503).

(Exh. Unitil-MHC-Rebuttal-2, at 9; Tr. 11, at 1501; RR-DPU-58, Att.). This category includes all expenses related to the transfer agent, shareholder programs, the annual meeting of shareholders, and the production and mailing of quarterly shareholder reports and specific shareholder communications (Exh. Unitil-MHC-Rebuttal-2, at 8-9; Tr. 11, at 1501; RR-DPU-58, Att.).

Fitchburg initially sought to include in its cost of service its allocated share of expenses associated with all three of the aforementioned categories (Exhs. Unitil-MHC-Rebuttal-2, at 10; Tr. 11, at 1501-1502; Tr. 13, at 1698-1701; RR-DPU-58, Att.). Subsequently, the Company adjusted its proposed cost of service to exclude the allocated amounts of expense associated with the third category, Shareholder Direct (Exhs. Sch. RevReq-7-16 (Supp. 3) (electric); Sch. RevReq-7-17 (Supp. 3) (gas)). In doing so, the Company removed $21,099 from the electric division revenue requirement and $14,242 from the gas division revenue requirement (Exhs. Sch. RevReq-7-16 (Supp. 3) (electric); Sch. RevReq-7-17 (Supp. 3) (gas)). The Company now seeks to include in rates the allocated share of expenses associated with SEC and Compliance and Annual Reporting ($27,051 for the electric division and $18,262 for the gas division) (Exhs. Unitil-MHC-Rebuttal-2, at 10; Tr. 11, at 1501-1502; Tr. 13, at 1698-1701; RR-DPU-58, Att.).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department has a well-established policy of excluding shareholder expenses from the cost of service (Attorney General Brief at 65, citing D.T.E. 03-40, at 176; D.P.U. 94-50, at 326-327; The Berkshire Gas Company, D.P.U. 92-210, at 52 (1993); Western Massachusetts Electric Company, D.P.U. 88-250 (1989); D.P.U. 07-71, at 109-110). According to the Attorney General, the Company has failed to establish that the SEC and Compliance and Annual Reporting categories (1) represent an exception to this policy, (2) warrant treatment different from other shareholder service expenses, or (3) otherwise should be included in cost of service (Attorney General Brief at 65-66; Attorney General Reply Brief at 30). Accordingly, the Attorney General asserts that the expenses in SEC and Compliance and Annual Reporting categories should be excluded from the Company's cost of service (Attorney General Brief at 66; Attorney General Reply Brief at 30). In total, the Attorney General proposes to eliminate $43,000 and $33,000 of shareholder service expense from Fitchburg's electric and gas operation and maintenance expenses, respectively (Attorney General Brief at 65, citing Exhs. AG-DJE-1, at 9 (electric); AG-DJE-1, at 11 (gas)).

b. Fitchburg

The Company acknowledges that the Department's policy has been to exclude certain shareholder services from cost of service (Company Brief at 70). Although Fitchburg adjusted its initial request for recovery to exclude costs associated with the Shareholder Direct category of expenses, the Company maintains that the remaining costs provide many important benefits to customers, including ensuring the Company's continued access to capital markets (Company Brief at 69-70, citing Exh. Unitil-MHC-Rebuttal-2, at 10). As a result, the Company asserts that these costs are appropriate for recovery through rates and that no further adjustment to shareholder services expense is necessary (Company Brief at 69-70).

3. Analysis and Findings

The Department's policy is to exclude shareholder-related expenses from the cost of service. D.P.U. 07-71, at 110; D.P.U. 94-50, at 326-327; D.P.U. 92-210, at 52; D.P.U. 88-250, at 47. We acknowledge that the SEC and Compliance and Annual Reporting categories differ somewhat from the traditional shareholder service expenses. However, while we are able to discern a clear link between these expenses and the Company's shareholders, the Company has failed to establish a direct association between these expenses and benefits to ratepayers.[182] Therefore, the Department will exclude the SEC and Compliance and Annual Reporting categories from the Company's cost of service. The Company has already removed $35,341 in shareholder-related expenses from cost of service (Exhs. Sch. RevReq-7-16 (Supp. 3) (electric); Sch. RevReq-7-17 (Supp. 3) (gas)). Accordingly, Fitchburg's cost of service will be reduced by an additional $27,051 from its electric distribution operations and an additional $18,262 from its gas distribution operations, for a total of $45,313 from the Company's cost of service.

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[182] The Company states that if it were to prepare its request to recover shareholder services expense again, it would classify the costs differently (i.e., it would not classify the costs as shareholder-related) (Tr. 11, at 1502).

J. Service Company Costs

1. Allocation Method

a. Introduction

USC is a wholly-owned subsidiary of Unitil providing a variety of shared business functions to its utility affiliates at an "at cost" basis (Exhs. Unitil-MHC-1, at 11 (electric); Unitil-MHC-1, at 9 (gas)). USC provides services in the following six major functional areas: (1) corporate and administration; (2) customer services; (3) energy services; (4) engineering and operations; (5) regulatory, finance and accounting; and (6) technology (see Exh. AG-3-35, Att. (electric)). USC incurs common costs for shared services and provides client companies with service bills at the end of each month, consisting of direct charges and allocated costs (Exhs. AG-1-28, Att. 1, at 1-4 (electric); AG-21-2, Att. 1, at 20 (gas)). Costs that cannot be directly charged to an affiliate are allocated primarily using a three-factor allocator which is derived from the particular company's ratios of data for revenues, customers, and utility plant assets in relation to all of Unitil's affiliates (Exh. AG-21-2, Att. at 31 (gas)).

During the test year, USC billed to Fitchburg $341,135 in direct charges and $8,834,374 in allocated costs, for a total of $9,175,509 (Exhs. AG-1-28, Att. 2 (electric); AG-31-1, Att. (electric)). Of this amount, $4,966,844 was allocated to the Company's electric division and $4,208,626 was allocated to the Company's gas division (Exh. AG-1-28, Att. 2 (electric)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that Fitchburg has been evasive in providing details regarding cost allocations from USC and that the method by which USC allocates costs to its operating entities is not reasonable (Attorney General Brief at 85-88). The Attorney General contends that information in the initial filing regarding the costs that were directly charged and allocated to Fitchburg was incomplete, and that several rounds of follow-up discovery had to be issued before the Company provided the detailed information needed for the Attorney General to analyze the costs (Attorney General Brief at 87-88). In addition, the Attorney General claims that much of the information Fitchburg provided regarding cost allocations was inaccurate and/or misleading (Attorney General Brief at 89-90).[183]

Regarding the specific method USC uses to allocate costs to affiliates, the Attorney General takes issue with both the Company's characterization of direct charges versus allocated costs and the proportion of costs that are allocated as opposed to charged directly (Attorney General Brief at 92-97). The Attorney General claims that many of the costs being labeled as "direct charges" are, in fact, allocated costs and that USC has not appropriately charged costs directly to operating entities responsible for incurring the costs (Attorney General Brief at 91, 95-96). In particular, the Attorney General maintains that

[183] For example, the Attorney General notes that the Company provided an incomplete and high level description of the Unitil Time and Billing System when asked to provide allocation formulas and assumptions used to allocate expenses from USC (Attorney General Brief at 89-90).

although the Company claims that labor charges should be directly charged to affiliate companies, these costs are charged using allocators because USC employees are allotting the majority of their time at the end of each month to client companies using allocation guidelines (Attorney General Brief at 93-95). To address this issue, the Attorney General asserts that the Department should require USC to: (1) directly charge costs to operating entities responsible for incurring the costs; and (2) allocate, using cost causation principles, only those costs that cannot be direct charged (Attorney General Brief at 96-97; Attorney General Reply Brief at 23).

ii. Fitchburg

The Company contends that the Attorney General's allegations that the Company had obfuscated its service company charges and was evasive in its responses to information requests are false (Company Brief at 75). Instead, Fitchburg argues that some of the Attorney General's information requests were vague and that, once it was clear what information was being sought, the Company provided complete responses (Company Brief at 75). The Company further contends that it responded in good faith to numerous information requests with explanations of USC's service charges, providing trial balances, monthly invoices, USC's Employee Time Charge Guidelines, USC's Cost Allocation Manual, and supporting documentation (Company Brief at 75).

Further, the Company argues that there is nothing unusual or unreasonable about the method of allocating costs from USC to its affiliates (Company Brief at 76). The Company contends that the method for allocating service company costs has been previously accepted by the Department and that the charges to Fitchburg are legitimate, fair, and reasonably allocated (Company Brief at 76). Further, the Company claims that the while the Attorney General takes issue with the terminology used to describe the costs being allocated, she does not dispute the actual amount of charges allocated (Company Brief at 76). The Company maintains that virtually all service companies allocate costs in a similar manner to the approach used by USC, and that it is normal for a service company to “direct charge” an “allocated amount” of an expense to an affiliate (Company Brief at 76). Moreover, the Company argues that requiring USC to change its method of allocating service company costs to its affiliates would result in inefficiencies, redundancies in the provision of shared services, and higher costs for Fitchburg customers (Company Brief at 77). Finally, the Company asserts that such a change in method would result in confusion and complexity in operation with other regulatory jurisdictions that rely on and accept USC’ s current allocation methods (Company Brief at 77).

c. Analysis and Findings

The Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a formula that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 95-118, at 41; D.P.U. 89-114/90-331/91-80 (Phase One) at 79-80; Milford Water Company, D.P.U. 92-101, at 42-46 (1992); D.P.U. 85-137, at 51-52. In addition, 220 C.M.R. § 12.04(3) provides that an affiliated company may sell, lease, or otherwise transfer an asset to a distribution company, and may also provide services to a distribution company, provided that the price charged to the distribution company is no greater than the market value of the asset or service provided.

The services that USC provides to Fitchburg are necessary to the Company's business and, therefore, specifically benefit Fitchburg. Moreover, these activities do not duplicate services provided by the Company's local personnel. The Attorney General has raised issues concerning the method that USC employs to allocate its costs to Fitchburg.

As an initial matter, we find no support for the Attorney General's assertion that the Company was purposely evasive and obfuscated service company charges. In response to the Attorney General's first set of information requests, the Company provided an overview of the USC time and billing system, a breakdown of service company costs charged to Fitchburg, and expenses by account number (Exh. AG-1-28, Atts. 1-5 (electric)). When further and more detailed information was sought, the Company provided the Department and the Attorney General with time charge guideline allocation factors, a cost allocation manual, information on direct versus allocated costs, the monthly service bills sent to Fitchburg from USC, and other supporting documents and breakdowns of costs (Exhs. AG-3-35, Att. (electric); AG-3-37, Atts. 1-5 (electric); AG-31-1, Att. (electric); AG-31-7, Att. (electric); AG-21-2, Att. (gas)). Accordingly, the Department finds that the Company has provided sufficient information regarding the processes by which USC allocates costs to Fitchburg.

The Attorney General also argues that the method USC uses to allocate common costs to Fitchburg is not reasonable (Attorney General Brief at 85-97). The Attorney General's argument concerns how the costs are classified by USC and, in particular, the labeling of costs as "direct" or "allocated" (Attorney General Brief at 91-97). As discussed below, we have reviewed the record and are persuaded that the method USC uses to allocate common costs to Fitchburg is appropriate. While the Attorney General raises valid points about direct assignment versus allocation of common costs, her concerns are misplaced here.

USC's cost allocation manual specifies that direct assignment of costs is performed whenever practicable and is the preferred method of assigning costs to affiliates (Exh. AG-21-2, Att. 1, at 13 (gas)). In the absence of a clear relationship between the cost and the affiliate or when costs cannot be directly assigned, the cost allocation manual specifies that these costs are to be allocated using cost-causative allocation factors to the extent such allocation factors can be applied, with general allocation factors used to allocate any remaining costs (Exh. AG-21-2, Att. 1, at 13 (gas)); RR-DPU-59, Att. 1, at 188-189).

In describing the method by which costs are directly assigned or allocated, the cost allocation manual distinguishes between direct costs and indirect costs (Exh. AG-21-2, Att. 1, at 9, 29-30 (gas)). As defined by USC, a direct cost is one that can be associated with a particular service or product, labor, or materials for a specific project (see Exh. AG-21-2, Att. 1, at 9, 29 (gas)). By way of example, USC labor costs that can be identified with specific projects are classified as "direct labor" costs, and are billed to affiliates based on employee time cards (Exh. AG-21-2, Att. 1, at 29 (gas)). All other USC costs that cannot be specifically identified with a particular project are classified as indirect costs (see Exh. AG-21-2, Att. 1, at 9, 29 (gas); RR-DPU-59, Att. 1, at 182). Indirect costs consist of: (1) "indirect labor" costs (i.e., pension, insurance, payroll taxes, employee savings plans, and similar items); and (2) administrative and general costs that cannot be identified with or directly charged to a specific project (e.g., USC's costs associated with running the cash pool (Exh. AG-21-2, Att. 1, at 29-30 (gas)). Indirect labor costs are added to USC' s direct labor costs through the use of an overhead factor, while administrative and general costs are accumulated in a USC administrative overhead pool and charged back to affiliates (Exh. AG-21-2, Att. 1, at 29-30 (gas)).

USC's administrative and general costs consist of 17 areas, with costs allocated in most of those areas using a three-factor allocator based on revenue, customers, and utility plant assets of USC's affiliates (Exh. AG-3-37, Atts. 1-5 (electric); AG-21-2, Att. 1, at 31 (gas)). This allocation method is representative of what has been referred to as a modified Massachusetts formula.[184] In those instances where the three-factor allocator is not used, other allocators are used depending on the nature of the cost and causation, such as plant assets and employee headcounts (Exh. AG-3-37, Atts. 1-5 (electric); AG-21 -2, Att. 1, at 13 (gas)).

[184] The Massachusetts formula is a three-part allocator that uses a WACC ratio comparing gross revenues, plant, and payroll. D.P.U. 08-27, at 85 n.47. The Commonwealth originally developed the Massachusetts formula in 1919 for the purpose of apportioning income tax liabilities for companies with multi-state operations. See Acts of 1919, c. 355, § 19. Since that time, regulatory commissions across the United States have used this general approach and variations thereon, including modified Massachusetts formulas, to apportion common costs among utility companies that operate in multiple jurisdictions. D.P.U. 08-27, at 85-86 n.47.

The Massachusetts formula in its various forms is a well-established allocation method that is familiar to utilities and regulators. For many years, federal and state regulatory commissions have recognized both the original Massachusetts formula and those variations that have developed over time as suitable allocation methods. D.P.U. 10-114, at 187; D.P.U. 08-27, at 85 n.47; Eastern Edison Company, D.P.U. 1130, at 29-31 (1982). Regardless of the particular allocation method ultimately selected, however, the Department requires that the allocation method be driven by cost causation principles. D.P.U. 85-137, at 51-52.

The Department has reviewed the allocation factors used by USC, including the cost allocation manual and its appendices. We have also taken into consideration the basis for the various allocation factors, and USC's characterization of direct and indirect charges. Based on our review, we find that the Company has appropriately distinguished between those charges that are directly billable to USC's affiliates and those that are allocated to USC's affiliates through the use of the three-factor formula and other allocation methods. Based on the foregoing, the Department finds that the service costs being allocated to Fitchburg are done by a formula that is both cost-effective and non-discriminatory. The proposed allocations to Fitchburg represent activities that specifically benefit the Company and do not duplicate services already provided by Fitchburg. Therefore, the Department approves the Company's method of allocating service company costs, and we find the costs to be appropriate for inclusion in rates.

2. Employee Expenses

a. Introduction

During the test year, USC allocated $9,142 to the Company's gas division and $13,543 to the Company's electric division for employee reimbursements to officers and directors (Exh. AG-1-38, Att. at 2, 3 (electric)). These reimbursable employee expenses include items such as air and ground transportation, lodging, business meals, and miscellaneous expenses (Exh. AG-1-38, Att. at 1 (electric)). Fitchburg removed certain reimbursed expenses associated with two executives from the test year O&M expense as the expenses were considered to be below-the-line (Exhs. AG- 18-39 (electric); AG- 18-41 (electric)).[185] These adjustments total $661 for the Company's gas division and $979 for the Company's electric division (Exhs. AG-18-39, Att. 1 (electric); AG-18-41, Att. 3 (electric)). During proceedings, the Company also made an adjustment to remove $104 from the electric division cost of service and $70 from the gas division cost of service in credit card late fees associated with employee reimbursements (Exhs. Sch. RevReq 7-16 (Supp. 2) (electric); Sch. RevReq 7-17 (Supp. 2) (gas)).

[185] For ratemaking purposes, the term "below-the-line" refers to activities related to non-utility operation, and none of the revenues or expenses associated with such activity are included in a Company's revenue requirement. See D.P.U. 08-35, at 152; D.P.U. 07-71, at 63; Essex County Gas Company, D.P.U. 87-59, at 10 (1987).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should disallow certain reimbursable employee expenses that Fitchburg has included in its cost of service as they do not benefit the Company's Massachusetts ratepayers (Attorney General Brief at 98). Specifically, the Attorney General cites several expenses that she contends do not appear to benefit Fitchburg ratepayers, such as charges related to trips to New York City and Kansas City, exorbitant hotel stays and meals, and meetings with New Hampshire customers and the Maine Public Utility Commission (Attorney General Brief at 98-99, citing Exhs. AG-18-39 (electric); AG-18-40 (electric); AG-18-41 (electric)). The Attorney General also highlights a charge of approximately $7,000 related to a retirement party for USC's chief information officer (Attorney General Brief at 99, citing Exh. AG-18-40, Att. 2, at 10 (electric); Tr. 13, at 1641-1642; Attorney General Reply Brief at 25). The Attorney General asserts that there is no record evidence that supports these costs as benefiting ratepayers (Attorney General Brief at 100; Attorney General Reply Brief at 26). Alternatively, the Attorney General states that the Department should condition the approval of the aforementioned costs on a full accounting by Fitchburg demonstrating that each expense is properly allocated and of benefit to customers (Attorney General Brief at 100).

ii. Fitchburg

The Company argues that the travel-related employee expenses allocated from USC to Fitchburg are reasonable and were incurred to benefit all of Unitil companies, including

Fitchburg (Company Brief at 77). Further, the Company contends that the Attorney General has not presented any evidence demonstrating that these travel expenses are not justifiable (Company Brief at 77; Company Reply Brief at 33). The Company asserts that the expenses are well documented and were incurred in the ordinary course of business and, therefore, should be included in the cost of service (Company Reply Brief at 33).

c. 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. D.T.E. 03-40, at 140-141; Oxford Water Company, D.P.U. 1699, at 13 (1984). This standard applies whether the expenses were incurred at the parent level or at the service company level. D.T.E. 03-40, at 140-141.

As noted by the Attorney General, the employee reimbursements the Company has included in its cost of service do not contain sufficient explanation to ensure that the costs were incurred for the benefit of Massachusetts ratepayers (see Exhs. AG-18-39, Atts. 1-2 (electric); AG- 18-40, Atts. 1-2 (electric); AG- 18-41, Atts. 1-3 (electric)). The Company provides corporate credit card statements for three of USC’s directors and executives but no other documentation to demonstrate that such costs were reasonable or for the benefit of Fitchburg’s customers (Exhs. AG-18-39, Atts. 1-2 (electric); AG-18-40, Atts. 1-2 (electric); AG-18-41, Atts. 1-3 (electric)). While the credit card statements outline the various costs of meals, stays at hotels, car washes, gas, and even subscriptions to satellite radio, no further explanation or documentation is provided as to the purpose of these costs or how Massachusetts ratepayers benefit from these costs (see Exhs. AG-18-39, Att. 2 (electric); AG-18-40, Att. 2 (electric); AG-18-41, Att. 2 (electric)). While many of these costs are clearly questionable, even those that appear to be innocuous are insufficiently documented.

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. Fitchburg bears the burden of demonstrating that only costs that benefit Massachusetts ratepayers are allocated to the Company. Therefore, the Department rejects the Company's attempt to shift its burden onto the Attorney General by claiming that she has not demonstrated that the employee expenses are not appropriate for recovery.

For the reasons discussed above, the Department will remove $12,460[186] and $8,411[187] from the respective electric and gas division cost of service proposed by the Company. Going forward, the Department reminds all utility companies of their obligation to include sufficient detail about the nature and purpose of employee expenses for which reimbursement is sought, including explanations 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. The risk of non-recovery of claimed expenses looms for any utility that fails to do so.

186 This amount is calculated as $13,543 minus $104 in credit card late fees and $979 in below-the-line expenses that Fitchburg had already removed from cost of service.

187 This amount is calculated as $9,142 minus $70 in credit card late fees and $661 in below-the-line expenses that had already been removed by the Company.

3. Northern Utilities Acquisition Synergy Savings

a. Introduction

On November 18, 2008, the Department approved the sale by Bay State Gas Company, n/k/a Columbia Gas of Massachusetts ("Bay State"), of all of the capital stock of Northern Utilities ("Northern")[188] to Fitchburg's parent company, Unitil. Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A (2008).[189] As a result of the transaction, Fitchburg was expected to receive $1.7 million in synergy savings because of lower administrative overheads arising from Unitil's acquisition of Northern and Granite, and the resulting efficiencies gained by sharing the centralized service infrastructure of USC. D.P.U. 08-43-A at 44-45.

In the instant proceedings, Fitchburg states that in the test year it realized $1.1 million in synergy savings as a result of the Northern acquisition (Exhs. Unitil-MHC-Rebuttal-2, at 17-18; Unitil-MHC-Rebuttal-2A at 3). The synergies indentified by the Company principally occur at the level of costs for shared services from USC (Exhs. Unitil-MHC-Rebuttal-2, at 17; Unitil-MHC-Rebuttal-2A at 1). However, the Company

188 Northern is a New Hampshire corporation and a public utility that provides natural gas distribution services in New Hampshire and southern Maine. D.P.U. 08-43-A at 4.

189 The Northern stock sale was part of a transaction that also involved the sale to Unitil of all of the stock of Granite State Gas Transmission, Inc. ("Granite") by Bay State's parent, NiSource, Inc. D.P.U. 08-43-A at 5. Granite is a federally-regulated interstate natural gas transmission company primarily serving Northern in New Hampshire and Maine. D.P.U. 08-43-A at 4. Although the purchase of Northern and Granite was completed on December 1, 2008, the first full year of operation of Northern under the Unitil holding structure was 2009 (Tr. 1, at 29-30).

states that there are additional synergies that are analyzed at the local operating company level by comparing pre- and post-acquisition costs, including local operating costs as well as allocated direct charges such as insurance and benefit plan administration costs (Exh. Unitil-MHC-Rebuttal-2, at 17). In addition, Fitchburg submits that there are qualitative cost savings synergies from post-acquisition operating efficiencies, systems upgrades, and enhanced functional management resource improvements (Exh. Unitil-MHC-Rebuttal-2, at 17-18).

Fitchburg calculated the reported cost savings as the difference between the amount of shared services paid to USC in 2009, $6.1 million, and the pro-forma fees the Company would have paid to USC in 2009, $7.2 million, had the Northern acquisition not occurred (Exhs. Unitil-MHC-Rebuttal-2, at 19; Unitil-MHC-Rebuttal-2A at 3). The Company acknowledges that the overall cost savings are $0.6 million lower than the original estimate of $1.7 million (Exh. Unitil-MHC-Rebuttal-2, at 19).

Fitchburg offers two reasons for the difference between realized savings and expected savings. First, the Company cites its increased assumption of allocated USC labor costs following the transfer of three employees from Fitchburg to USC after the Northern acquisition (Exhs. Unitil-MHC-Rebuttal-2, at 19; Unitil-MHC-Rebuttal-2A at 3). Fitchburg states that the employee transfer was intended to better align gas operations and to achieve operating efficiencies and service improvements (Exh. Unitil-MHC-Rebuttal-2, at 19).[190] Second, the Company submits that USC provided certain enhanced functional management services to Fitchburg in 2009 that were not part of the original synergy cost saving analysis (Exh. Unitil-MHC-Rebuttal-2, at 19-20). The Company states that these functional improvements to operations were in the areas of: (1) emergency storm response and preparedness; (2) communications and municipal relations; and (3) centralized dispatch and control, principally relating to adopting improvements as a result of Winter Storm 2008 (Exh. Unitil-MHC-Rebuttal-2, at 20).

Fitchburg states that the total cost of the above-noted employee transfers and the enhanced functional services provided to the Company in 2009 accounted for an increase in USC charges to Fitchburg of approximately $0.5 million (Exh. Unitil-MHC-Rebuttal-2, at 20). The Company, therefore, concludes that the resulting total actual amount of quantifiable synergy saving in the 2009 test year for Fitchburg is very close to the original $1.7 million estimate (Exh. Unitil-MHC-Rebuttal-2, at 20).

Finally, the Company asserts that customers have received all of the synergy cost savings in Fitchburg's 2009 test year cost of service, and have incurred none of the costs associated with the Northern acquisition (Exh. Unitil-MHC-Rebuttal-2, at 20). Further, the Company states that since the post-acquisition synergy cost savings have been established, those synergy savings will continue to benefit Fitchburg's customers (Exh. Unitil-MHC-Rebuttal-2, at 20).

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[190] Specifically, the Company states that the following three manager level positions were transferred from the Fitchburg operating payroll to the USC payroll: (1) a gas operations director; (2) a gas dispatch manager; and (3) a gas controller (Exh. Unitil-MHC-Rebuttal-2, at 19-20).

b. Position of the Parties

i. The Attorney General

The Attorney General argues that the Company's ratepayers are entitled to a cost of service reduction of $1.2 million (Attorney General Brief at 103; Attorney General Reply Brief at 27). The Attorney General calculates this amount as the difference between the expected annual cost savings of $1.7 million and approximately $500,000 of actual reduction in USC expenses charged to Fitchburg from 2008 to 2009 (Attorney General Brief at 103; Attorney General Reply Brief at 27).

The Attorney General notes that in D.P.U. 08-43-A, Unitil contended that there would be significant, system-wide cost savings as a result of the Northern acquisition, and specific savings to Fitchburg as well (Attorney General Brief at 101, citing D.P.U. 08-43-A at 41-42; see also Exhs. AG-DR-1, at 3-4; AG-DR-2).[191] Further, the Attorney General adds that the

[191] More specifically, the Attorney General notes that Unitil expected system-wide synergies of approximately $5.6 million per year, $5.1 million of which were related to shared centralized management and administrative services provided by USC (Attorney General Brief at 101, citing D.P.U. 08-43-A at 41-42; see also Exh. AG-DR-1, at 3). Further, the Attorney General states that the annual synergy savings applicable to Fitchburg of $1.7 million would result from efficiencies gained by sharing USC functions with Northern and Granite (Attorney General Brief at 101, citing D.P.U. 08-43-A at 41-42; see also Exh. AG-DR-1, at 3). According to the Attorney General, the total projected savings to Fitchburg including both expense and capital savings presented in the case were $2.46 million, $1.7 million of which were expense savings (Attorney General Brief at 101, citing Exhs. AG-DR-1, at 3-4; AG-DR-2).

Department, in its Order in D.P.U. 08-43-A, found that as a result of the Northern acquisition the expected savings to Fitchburg's customers "are not inconsequential for Fitchburg" and stated that it "expects Unitil will include those customer savings in Fitchburg's next base rate case" (Attorney General Brief at 101, citing D.P.U. 08-43-A at 45; Attorney General Reply Brief at 27). The Attorney General asserts that the expected level of savings promised by Unitil either has not come to fruition or has not been passed on fully to Fitchburg under its cost allocation methods (Attorney General Brief at 101; Attorney General Reply Brief at 27).

In particular, the Attorney General argues that the total annual costs charged to Fitchburg by USC did not decline by the level projected by Unitil in D.P.U. 08-43-A (Attorney General Brief at 101-102, citing Exh. AG-3-35, Att. 1 (electric)).[192] Further, the Attorney General asserts that the expense components of those total annual costs declined by just under $500,000, not the $1.7 million amount presented by Unitil in D.P.U. 08-43-A (Attorney General Brief at 102, citing Exh. AG-21-4, Att. 1 (electric); Attorney General Reply Brief, at 27).[193] Accordingly, the Attorney General recommends that additional cost reduction of $1.2 million be passed on to Fitchburg from USC in this case (Attorney General Brief at 103; Attorney General Reply Brief at 27).

[192] The components of the indicated annual total costs charged to Fitchburg by USC consist of: (1) corporate and administration; (2) customer service; (3) energy services; (4) engineering and operations; (5) regulatory, finance and accounting; (6) technology; and (7) direct charges assigned to Fitchburg (Attorney General Brief at 102, citing Exh. AG-3-35, Att. 1 (electric)).

[193] The 2008 and 2009 expense components were determined as the difference between the total annual costs and capital costs (2008: $10,181,595 – $2,900,096 = $7,281,499; 2009: $9,175,509 – $2,390,182 = $6,785,327) (Attorney General Brief at 102, citing Exh. AG-21-4, Att. 1). Although the Attorney General's indicated expense component for 2009 of $6,210,018 was incorrectly calculated, the claimed $496,171 expense reduction from 2008 to 2009 is correctly calculated ($7,281,499 – $6,785,327 = $496,172) taking into account rounding (Exh. AG-21-4, Att. 1 (electric)).

The Attorney General rejects the Company's explanation for the $0.6 million reduction in expected synergy cost savings, and argues that the labor costs associated with the three employees whose time is now being allocated to, instead of being booked directly by Fitchburg, would not add up to a $600,000 offset to the projected savings (Attorney General Reply Brief at 27, citing Company Brief at 79; Exh. Unitil-MHC-Rebuttal-2, at 19). Further, the Attorney General also contends that the Company has not provided any quantification of the costs to Fitchburg of the enhanced functional management services claimed to have been provided by USC in 2009 that were not part of the original acquisition saving calculations (Attorney General Reply Brief at 27).

ii. Fitchburg

The Company claims that the Attorney General's recommendation to reduce by $1.2 million the expenses allocated from USC to Fitchburg is not supported by the record and should be rejected (Company Brief at 78; Company Reply Brief at 33). The Company also claims that the Attorney General erred in her calculations by assuming that acquisition synergy savings would have occurred only if the results reduce the Company's total cost of service to a level below what it was in 2008 (Company Brief at 78; Company Reply Brief at 33).

Fitchburg contends that the fundamental matter in dispute is how to calculate the synergy cost savings (Company Reply Brief at 33). In that regard, the Company asserts that the correct way to calculate the synergy cost saving is to take the difference between Fitchburg's costs after the acquisition and what those costs would have been if the acquisition had not occurred (Company Brief at 78, citing Exh. Unitil-MHC-Rebuttal-2, at 17; Company Reply Brief at 34). Further, the Company claims that acquisition synergies would reduce the growth in the Company's costs and not the nominal level of costs as they existed in 2008 (Company Brief at 78; Company Reply Brief at 33). Fitchburg contends that the Attorney General has ignored the circumstances that the savings may be fully achieved, but that there may also be offsetting growth in the Company's costs that may be occurring at the same time rather than reducing the overall level of cost below what it was in 2008 (Company Reply Brief at 33-34).

Fitchburg asserts that it has demonstrated $1.1 million in synergy cost saving resulting from the Northern acquisition (Company Brief at 79, citing Exh. Unitil-MHC-Rebuttal-2, at 17; Company Reply Brief at 34). The Company claims that this amount was presented to and accepted by the New Hampshire Public Utilities Commission ("NHPUC") (Company Brief at 79, citing Exh. Unitil-MHC-Rebuttal-2 at 18). The Company also claims that the Attorney General agrees that USC's charges to Fitchburg decreased by $1.1 million in the 2009 test year compared to the 2008 level (Company Reply Brief at 34, citing Attorney General Reply Brief at 100-103). Thus, the Company asserts that it has shown actual savings and efforts to achieve as much savings as it could (Company Brief at 79).[194]

[194] The Company reiterates that the reasons why Fitchburg's synergy savings were $0.6 million less than the $1.7 million presented in D.P.U. 08-43 are twofold: (1) Fitchburg's allocation of USC labor costs increased as a result of the transfer of three employees from Fitchburg to USC, and (2) USC provided certain enhanced functional management services to Fitchburg in 2009 that were not part of the original synergy cost savings analysis (Company Brief at 79, citing Exh. Unitil-MHC-Rebuttal-2, at 19-20; Company Reply Brief at 34-35).

Finally, the Company contends that the Attorney General has not cited to any Department precedent or case law to support a proposed disallowance of $1.2 million in costs because the Company failed to achieve a certain level of projected merger synergies (Company Brief at 79; Company Reply Brief at 35). According to Fitchburg, the Attorney General's proposal to exclude this amount from the Company's cost of service would represent a disallowance of operating costs that are unchallenged in terms of reasonableness or prudent incurrence (Company Reply Brief at 35). In this regard, the Company argues that it is entitled to have rates that reflect a reasonable level of expenses necessary to provide service to its customers (Company Brief at 79). The Company claims that public utilities are permitted to charge rates that are compensatory of the full cost incurred by efficient management, except where the Department deems costs to be excessive, unwarranted, or incurred in bad faith (Company Reply Brief at 35, citing Boston Gas Co. v. Department of Pub. Utils., 387 Mass. 531, 539 (1982); New England Tel. & Tel. Co. v. Department of Pub. Utils., 371 Mass. 67, 79 (1976); New England Tel. & Tel. Co. v. Department of Pub. Utils., 360 Mass. 443, 483-484 (1971)). The Company asserts that a decision by the Department to disallow $1.2 million in operating expenses would require a finding that the costs incurred by the Company are unreasonable or imprudently incurred or are excessive, unwarranted, or incurred in bad faith (Company Reply Brief at 35). The Company concludes that a reduction in a Company's cost of service, because a certain level of merger synergies was not achieved, would be unprecedented, based on a faulty premise, and without legal foundation (Company Brief at 79; Company Reply Brief at 35).

c. Analysis and Findings

In the past, the Department has stated that the evaluation of savings from a merger or acquisition is not subject to the same level of precision as generally can be attained in a traditional rate case, and that projected savings must be based on figures that are reasonable estimates. Boston Edison Company/Commonwealth Energy Acquisition, D.T.E. 99-19, at 68-69 (1999); Eastern/Colonial Acquisition, D.T.E. 98-128 (1999). Also, the Department has stated under our prior standard for evaluating mergers that a finding that a proposed merger or acquisition would probably yield a net benefit does not mean that such a transaction must yield a net benefit to satisfy G.L. c. 164, § 96. Southern Union/Fall River Gas Company, D.T.E. 00-26, at 5, n.4 (2000).[195]

[195] In NSTAR/Northeast Utilities Merger, D.P.U. 10-170, the Department issued an Interlocutory Order changing the standard for transactions under G.L. c. 164, § 96 to now require a showing of net benefits rather than a showing of no net harm. D.P.U. 10-170, at 27 (March 10, 2011).

The Department addresses here two related issues: (1) the appropriate method of calculating the Northern acquisition synergy savings that were realized by Fitchburg in the 2009 test year; and (2) whether Fitchburg's inability to realize in 2009 the expected savings of $1.7 million presented in D.P.U. 08-43-A, after the Northern acquisition, would necessitate a reduction in Fitchburg's 2009 test year cost of service to the extent that such level of expected saving was not fully realized.

In D.P.U. 08-43-A at 44-45, the Department stated that Fitchburg was expected to receive savings in the amount of $1.7 million as a result of lower administrative overhead costs and efficiencies gained by sharing the centralized service infrastructure of USC. These expected savings were calculated as the difference between the estimated pre-acquisition fees payable to USC by Fitchburg and the corresponding fees payable post acquisition (Exh. AG-DR-2, at 2). This savings estimate was based on an analysis using 2007 data that Unitil filed with NHPUC on June 26, 2008 (Exh. Unitil-MHC-Rebuttal-2, at 18).[196]

Using the same method used in its filing in D.P.U. 08-43-A, but based on 2009 actual data, the Company calculated a synergy cost savings for Fitchburg for the 2009 test year in the amount of $1.1 million (Exhs. Unitil-MHC-Rebuttal-2, at 18; Unitil-MHC-Rebuttal-2(A) at 3). These realized savings were calculated as the difference between the pro-forma USC fees

196 The estimated pre- and post-acquisition USC fees payable by Fitchburg were $6.7 million and $5.0 million, respectively, for a resulting expected expense reduction or savings of $1.7 million ($6.7 million – $5.0 million) (Exh. AG-DR-2, at 2). Exhibit AG-DR-2 is a copy of Unitil's supplemental response dated June 26, 2008 in Docket No. DG 08-048, in which the NHPUC approved Unitil's acquisition of Northern.

payable by Fitchburg, had the acquisition not occurred, and the actual amount paid by Fitchburg to USC in 2009 (Exhs. Unitil-MHC-Rebuttal-2, at 19; Unitil-MHC-Rebuttal-2(A) at 3).[197]

The approach used by the Attorney General in calculating the savings realized from the Northern acquisition, as her basis for recommending a $1.2 million reduction in Fitchburg's test year cost of services, is different from the above-described approach used by the Company. More specifically, the Attorney General noted that the total annual actual costs (capital and expense) allocated and assigned to Fitchburg by USC in 2008 and 2009 were $10,181,595 and $9,175,509, respectively (Exh. AG-DR-1, at 5, citing Exh. AG-3-35, Att. 1 (electric)). The expense components of those total annual costs were $7,281,499 and $6,785,327, respectively (Exh. AG-21-4, Att. 1 (electric)). Therefore, the actual expenses allocated and assigned to Fitchburg by USC declined by $496,172 from 2008 to 2009 ($7,281,499- $6,785,327).

The Attorney General argued that since this amount of actual expense reduction from 2008 to 2009 is well below the $1.7 million expense saving presented by Unitil in D.P.U. 08-43-A, an additional reduction to expenses allocated from USC to Fitchburg in the

[197] The pro-forma USC fees payable by Fitchburg, had the acquisition not occurred, and the actual USC 2009 fees paid by Fitchburg were $7.2 million and $6.1 million, respectively, for a resulting realized saving of $1.1 million ($7.2 million – $6.1 million) (Exh. Unitil-MHC-Rebuttal-2(A) at 3). Exhibit Unitil-MHC-Rebuttal-2(A) is a copy of Unitil's response dated May 21, 2010 in Docket No. DG 08-048, a continuing review by NHPUC of how Unitil might operate Granite and Northern for the benefit of customers.

amount of $1.2 million should be included in this case (Attorney General Brief at 102-103; Attorney General Reply Brief at 27). The Attorney General explained that this $1.2 million reduction is equal to the $1.7 million presented in D.P.U. 08-43-A minus the approximately $500,000 actual reduction in expenses from 2008 to 2009 (Attorney General Brief at 103).

The record, however, shows that, as a result of the Northern acquisition, a synergy cost saving of $1.1 million was actually realized by Fitchburg in the 2009 test year (Exh. Unitl-MHC-Rebuttal-2A). Although the actual cost savings are approximately $0.6 million less than the $1.7 million presented in D.P.U. 08-43-A, the Company explained that Fitchburg's allocation of USC's labor costs increased because of three manager-level employees that were transferred from Fitchburg operating payroll to USC payroll (Exh. Unitil-MHC-Rebuttal-2, at 19). In addition, the Company explained that USC provided certain enhanced functional management services to Fitchburg in 2009 that were not part of the original synergy cost savings analysis, and that the costs for these services would have further increased the amount of charges allocated to and assigned to Fitchburg (Exh. Unitl-MHC-Rebuttal-2, at 19-20). We find that the Company has provided a reasonable explanation of the difference between the synergy savings estimate stated in D.P.U. 08-43-A and the synergy savings realized, and that the explanation is adequate in light of our prior standard for evaluating transactions under c. 164, § 96 ("Section 96"). However, we emphasize, particularly in the context of the revised standard for Section 96 transactions that the Department will rely on an applicant's estimation of savings and, under different circumstances, may find that a different ratemaking treatment for disparities between estimated and realized synergy savings is appropriate.

Although the Company has not provided calculations on the actual costs of the three employees transferred to USC and that of the enhanced functional management services provided by USC to Fitchburg, we accept for the purpose of this case the Company's representation that the corresponding total cost during the test year is approximately $500,000 (Exh. Unitil-MHC-Rebuttal-2, at 20). Absent such additional costs, the actual synergy cost saving would have been $1.6 million or $100,000 less than the original amount presented in D.P.U. 08-43-A (Exh. Unitil-MHC-Rebuttal-2, at 19-20).

The Department has previously concluded under its prior standard for evaluating mergers that finding that a proposed merger or acquisition would probably yield a net benefit does not mean that such a transaction must yield a net benefit to satisfy G.L. c. 164, § 96. D.T.E. 00-26, at 5, n.4. We find the Company's method of determining the actually-realized synergy savings, that compares the 2009 actual USC charges to Fitchburg with the 2009 pro-forma USC charges to Fitchburg, had the Northern acquisition not occurred, to be reasonable and consistent with the method presented in D.P.U. 08-43-A. Accordingly, in this case, we accept such a method and the results of the Company's calculations.

K. Active Hardship Protected Receivables

1. Introduction

Hardship protected accounts are residential service accounts that apply to customers who are protected from shut-off by a utility for non-payment. 220 C.M.R. §§ 25.03, 25.05.

To quality for protected status from service termination, customers must be elderly or demonstrate that they have a financial hardship and meet certain other requirements, such as suffering from a serious illness or residing with a child under twelve months of age. See 220 C.M.R. § 25.03(1); 220 C.M.R. § 25.03(3); 220 C.M.R. § 25.05(3). Customers who meet the income eligibility requirements for the federal Low Income Home Energy Assistance Program ("LIHEAP") are deemed to have a financial hardship. 220 C.M.R. § 25.01(2).

Many accounts remain in protected status for years, and during this time the Company may not pursue collection or write-off the associated uncollected revenues without incurring a significant charge to equity (see Exh. Unitil-MHC-Rebuttal-2, at 23-24). According to the Company, its accounts receivable balance has been increasing for several years, as the easing of eligibility requirements for LIHEAP has caused the number of customers qualifying for hardship protected status to increase (Exh. Unitil-MHC-Rebuttal-2, at 25-26).

2. Fitchburg's Proposal

As part of its case on rebuttal, the Company submitted a proposal to recover the accounts receivable balance for its active hardship protected accounts that are more than 350 days past due (Exh. Unitil-MHC-Rebuttal-2, at 32). For its electric division, the Company proposes to recover in base rates the amount of $430,544, which would be amortized over a five year period for an annual amortization amount of $86,109 (Exhs. Unitil-MHC-Rebuttal-2, at 32; Sch. RevReq-7-21 (Supp. 3) (electric)). For its gas division, Fitchburg proposes to recover in base rates the amount of $360,506, which would be amortized over a five-year period for an annual amortization amount of $72,101 (Exhs. Unitil-MHC-Rebuttal-2, at 32; Sch. RevReq-7-19 (Supp. 3) (gas)).[198] Under the Company's proposal, any payments received from active hardship protected customers who were more than 350 days past due would be credited back to all customers through the Residential Assistance Adjustment Clause ("RAAC") mechanism (Exh. Unitil-MHC-Rebuttal-2, at 33).

Fitchburg asserts that the growing balances on its hardship protected accounts, if declared to be an impaired asset, would cause the Company to "incur a significant charge to equity" that would "continue to create a financial strain on the Company" (Exh. Unitil-MHC-Rebuttal-2, at 24-26). The Company argues that it waited to submit the instant proposal until it had an opportunity to review of Department's decision in D.P.U. 10-70 and the treatment of the active hardship protected accounts in that proceeding (Tr. 13, at 1583). The Company asserts that its proposal to amortize the recovery of the accounts receivable balance for its active hardship protected accounts that are more than 350 days past due is consistent with the ratemaking treatment recently approved by the Department for WMECo in D.P.U. 10-70 (Company Brief at 58). No other party addressed this issue.

[198] This five-year horizon mirrors the amount of time for amortization that the Department approved for WMECo in D.P.U. 10-70 (Exh. Unitil-MHC-Rebuttal-2, at 32; see also D.P.U. 10-70, at 220).

3. Analysis and Findings

Fitchburg's proposal, if approved, would permit the Company to recover from ratepayers nearly $800,000 over the next five years (Exhs. Unitil-MHC-Rebuttal-2, at 32; Sch. RevReq-7-21 (Supp. 3) (electric); Sch. RevReq-7-19 (Supp. 3) (gas)). A proposal of this magnitude, which we find is neither uncontroversial nor routine, requires a full investigation. However, the Company submitted this proposal too late in the proceedings to allow for proper inquiry.

Fitchburg submitted its active hardship account proposal as part of its rebuttal testimony on April 20, 2011, more than three months after its initial filings were made. By this time, discovery on the Company's initial filings was closed and evidentiary hearings were well underway. In fact, the Attorney General began presenting her witnesses for cross-examination two days after the Company's rebuttal testimony was filed.

Fitchburg's explanation that it was justified in its late filing of the proposal because it first needed to review our decision in D.P.U. 10-70 is not persuasive. There was nothing preventing Fitchburg, as part of its initial filings, from proposing to recover the accounts receivable balance for its active hardship protected accounts. Further, if the growing balance in the active hardship account was presenting a strain on the Company's financial situation as Fitchburg contends, then it stands to reason that it would have presented its proposal to address this issue with its initial filing.[199] That the Company waited more than three months after its

[199] As the Company itself points out, the Commonwealth of Massachusetts expanded the eligibility for enrollment in this program twice in the past six years: once in 2005 (from 175 to 200 percent of the federal poverty level) and again in 2008 (from 200 percent of the poverty level to 60 percent of the estimated state median income) (Exh. Unitil-MHC-Rebuttal-2, at 25). Both of these changes to the LIHEAP eligibility requirements took effect well before the test year and we would expect that the Company would have realized any adverse effects of these changes prior to the time of the initial filings in the instant cases.

initial filing to submit this proposal does not convey the sense of urgency that the Company insists it now faces. Even assuming for the purpose of argument that it was reasonable for Fitchburg to await our decision in D.P.U. 10-70 prior to filing its request, the Company waited nearly three months after the Department issued the Order in that proceeding before filing its proposal. This is much too late.

Based on these considerations, we find that Fitchburg's delay in filing the proposal prevented the Department and other parties from properly investigating its request. Accordingly, we deny the Company's proposed recovery of the accounts receivable balance for its active hardship protected accounts that are more than *350* days past due. See, e.g., D.P.U. 92-111, at 10 (denying Bay State's request for approval of a base rate step adjustment due to late filing); Western Massachusetts Electric Company, D.P.U. 86-280-A at 26 (1987) (denying the inclusion of rate base costs due to the relevant information being provided on the last day of evidentiary hearings). Our decision today does not preclude Fitchburg, in its next rate case, from making a timely and well supported request for recovery of the accounts receivable balance for its active hardship protected accounts.

L. Other Consultant Expenses

1. Introduction

On March 12, 2009, the Department opened an investigation into the Company's gas procurement practices and docketed the matter as Fitchburg Gas and Electric Company, D.P.U. 09-09 (2009). On November 2, 2009, the Department issued a final Order and found, among other things, that Fitchburg acted imprudently by engaging in a gas purchasing program without Department approval. D.P.U. 09-09, at 41-42, 44-46, *53-54.* The Department directed the Company to refund $4,648,075, plus interest,[200] to its gas customers. D.P.U. 09-09, at 57. The Department's Order is currently under appeal to the Supreme Judicial Court. Fitchburg Gas and Electric Light Company, d/b/a/ Unitil v. Dep't of Public Utilities, SJC-10855.

During the pendency of the Department's investigation in D . P. U. 09-09, the Company submitted for Department approval a gas purchasing plan on May 11, 2009. The Department docketed this matter as Fitchburg Gas and Electric Light Company, D.P.U. 09-42. The matter is currently pending before the Department.

200 Including interest, the Company will refund the amount of $4,954,787 to its gas customers over five years (Exh. Unitil – MHC- 1, at 21 (gas)). For financial reporting purposes, the Company took the charge against income in December 2009 (Exh. Unitil – MHC-1, at 21 (gas)). The Company removed this non-recurring charge from the revenue requirement (Exh. Unitil – MHC-1, at 21 (gas)).

In the instant rate case proceedings, the Company has included in its proposed electric cost of service $117,738 in outside consulting costs purportedly related to work performed during the test year in D.P.U. 09-09[201] and $798 in costs incurred in 2010 (Exhs. AG-18-16 (electric); RR-DPU-69).[202] Fitchburg acknowledges that, despite being included in the electric division's cost of service, these are costs that were related to its gas operations (Exhs. AG-18-16 (electric); Tr. 7, at 755-756). Further, the Company indicates that these costs were incorrectly booked to Account 923 (Outside Services) rather than Account 928 (Regulatory Commission Expense) of the Uniform System of Accounts for Electric Companies (Exhs. AG-18-16 (electric); Tr. 7, at 755-756).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should remove from the Company's test year cost of service all consultant costs associated with D.P.U. 09-09 (Attorney General Brief at 64-65). The Attorney General contends that, consistent with Department precedent,

201 The Attorney General does not specifically address any consultants' costs associated with D.P.U. 09-42, nor does she address the $798 in costs incurred in 2010.

202 The record is unclear as to whether any of these costs are also attributable to D.P.U. 09-42. Initially, the Company identified these costs as being related only to D.P.U. 09-09 (Exh. AG-18-16). Although the Company later claims in its response to Record Request DPU-69 that some of these costs are associated with D.P.U. 09-42, it does not specify the amount. During evidentiary hearings, the Company testified that any costs attributable to D.P.U. 09-42 would be "minor" (Tr. 17, at 1743). Finally, on brief the Company addresses these costs only in the context of D.P.U. 09-09 (Company Brief at 68-69). Based on the record, we will analyze these costs as if they relate solely to D.P.U. 09-09.

the Company should not be allowed to recover from its customers imprudently incurred costs (Attorney General Brief at 64, citing Western Massachusetts Electric Company, D.P.U. 85-270, at 10 (1986)). The Attorney General notes that in D.P.U. 09-09, the Department disallowed recovery of approximately $4.6 million in gas purchasing costs that were incurred as a result of the Company's imprudent gas purchasing practices (Attorney General Brief at 63, citing D.P.U. 09-09, at 53-54, 56, 58). According to the Attorney General, the costs of consultants used in relation to the investigation in D.P.U. 09-09 would not have been incurred but for the Company's imprudent gas procurement strategy (Attorney General Brief at 64). Accordingly, the Attorney General argues that the Company should not be permitted to recover these consultant costs from ratepayers as they are a direct result of the Company's imprudence (Attorney General Brief at 64).

b. Fitchburg

Fitchburg argues that, although the Department found that the Company's gas purchases were imprudent, it is not appropriate to remove from its test year cost of service the costs that were incurred in order to defend itself in D . P. U. 09-09 (Company Brief at 69). The Company contends that it had a fundamental right to a defense in the D.P.U. 09-09 proceedings and, therefore, it is entitled to recover the costs of related to its defense (Company Brief at 68-69). Finally, the Company argues that regulatory expenses always exhibit an ebb and flow from year to year and, therefore, there is no reason to conclude that the test year level of expense, because it includes costs related to its defense in D.P.U. 09-09, is unrepresentative (Company Brief at 69).

3. Analysis and Findings

The Department typically includes a test year level of expenses in cost of service and will adjust this level only for known and measurable changes. See D.P.U. 07-71, at 120; D.P.U. 87-260, at 75. In this regard, the Department consistently has held that there are three classes of expenses that are recoverable through base rates: (1) annually recurring expenses; (2) periodically recurring expenses; and (3) non-recurring extraordinary expenses. D.T.E. 98-51, at 35; D.P.U. 95-118, at 121-122; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 32-33 (1983).

As an initial matter, the Company seeks to recover consultants' costs incurred in 2010 in the amount of $798 (Exh. AG-18-16 (electric)). The Department finds that these consulting costs were incurred outside of the test year and, therefore, the Company may not recover such costs. See D.P.U. 10-55, at 302-303; D.T.E. 03-40, at 284. Regarding the consultants' costs incurred during the test year, we find that the Company has failed to demonstrate that they are either annually recurring or periodically recurring expenses. The costs were incurred in relation to an unusual investigation opened by the Department to investigate Fitchburg's gas procurement practices. As evidenced by the magnitude of the refund to customers ordered by the Department, the proceeding in D.P.U. 09-09 was not a routine regulatory matter. We fully expect that this type of proceeding will not be an annually or periodically recurring event. Instead, we find that the consultant costs at issue are non-recurring expenses.

Nonrecurring expenses are ineligible for inclusion in the cost of service unless it is demonstrated that they are extraordinary in nature and amount as to warrant their recovery by amortizing them over a period of time. Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983). In this instance, we find that the consultants' costs are not extraordinary in nature or amount, particularly when viewed in light of the Company's total gas division test year operating revenues of $34,768,599 (Exh. Sch. RevReq-1, at 1 (Supp. 3) (gas)). Moreover, we conclude that disallowance of these costs would not significantly harm the overall financial condition of the Company. Accordingly, the Company's proposal to include these non-extraordinary, non-recurring costs in its cost of service is denied.

The Department will reduce the Company's cost of service by $118,536 to remove the costs incorrectly booked to Account 923 (Outside Services). Because the Department is excluding these expenses from the Company's cost of service for its gas division, no further adjustment is required.

M. Accounts 887 and 892 – Gas Division

1. Introduction

In 2008, Fitchburg booked $226,801 to Account 887 (Maintenance of Mains)[203] and $30,309 to Account 892 (Maintenance of Services)[204] for its gas division (Exhs. AG-1-34,

[203] Under the Uniform System of Accounts for Gas Companies, Account 887 (Maintenance of Mains) includes the cost of labor, materials used, and expenses incurred in the maintenance of transmission and distribution mains. See 220 C.M.R. §§ 50.00 et seq. For purposes of this account, cost items may be related to supervising, repairing and restoring mains, trenching, backfilling, etc. See 220 C.M.R. §§ 50.00 et seq.

[204] Under the Uniform System of Accounts for Gas Companies, Account 892 (Maintenance of Services) includes the cost of labor, materials used, and expenses incurred in the maintenance of services. See 220 C.M.R. §§ 50.00 et seq. For purposes of this account, cost items may be related to supervising, testing and inspection of services, repairing and restoring services, etc. See 220 C.M.R. §§ 50.00 et seq.

Att. (gas); AG-7-19, Att. at 1 (gas)). During the test year, the Company booked $283,661 and $78,013 to Accounts 887 and 892, respectively (Exhs. AG-1-34, Att. (gas); AG-7-19, Att. (gas)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the expenses charged to Accounts 887 and 892 were unusually high during the test year and, therefore, should be normalized to make them representative (Attorney General Brief at 56; Attorney General Reply Brief at 28). The Attorney General observes that the expenses charged to Accounts 887 and 892 decreased from 2009 to 2010[205] (Attorney General Brief at 56-57, citing, Exh. AG-1-34 (gas)). Based on this observation, she maintains that the 2009 levels of expenses in these accounts were outliers (Attorney General Reply Brief at 28). The Attorney General proposes normalizing the expenses charged to Accounts 887 and 892 based on the three-year average of expenses for the years 2008, 2009, and 2010 (Attorney General Brief at 57).

b. Fitchburg

Fitchburg asserts that costs in individual O&M accounts shift over time depending on where the focus of activity is for that period (Company Brief at 65, citing, Tr. 13,

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205 The Attorney General states that during 2010, the Company booked $252,000 to Account 887 and $27,000 to Accounts 892 (Exh. AG-DJE-1, at 9 (gas)).

at 1729-1730; Tr. 17, at 2273-2274). In particular, the Company states that the increases to Accounts 887 and 892 are a result of increased costs associated with Fitchburg's maintenance of transmission and distribution mains and services (Exh. AG-7-19, Att. at 1 (gas)).

Fitchburg argues that although expenses charged to individual accounts varied between 2008 and 2009, its overall O&M expense, excluding USC charges, increased by only $72,504 over this same period (Company Brief at 66, citing Exh. Unitil-MHC-Rebuttal-2, at 6; Tr. 17, at 2274). Accordingly, the Company argues that the Attorney General's proposed normalization adjustment is not appropriate (Company Brief at 65-55).

3. Analysis and Findings

Companies may include in their cost of service a representative level of recurring, non-extraordinary expenses as long as these expenses are reasonable. D.T.E. 98-51, at 39; D.P.U. 86-280-A at 49. The Department will employ normalization adjustments in instances where the test year level is not considered to be representative. See D.P.U. 10-114, at 167; D.P.U. 10-55, at 272.

Several of the Company's O&M expense accounts have experienced fluctuations between 2007 and 2010 (Exh. AG-1-34, Att. (gas)). Multiple accounts, including Accounts 887 and 892, experienced increases in expense levels; however, many accounts experienced decreases (Exh. AG-1-34, Att. (gas)). The Attorney General claims that the Company's 2009 O&M expense represents an increase of approximately $637,000 over the expense incurred in 2008; however, the majority of this increase is related to charges from USC, which are addressed in Section X.J, above.

The Department is satisfied by the Company's explanation of the increases to Accounts 887 and 892, and finds that the increased costs booked to these accounts represent changes that occur due to normal business activity (Exhs. AG-1-34, at 8 (gas), AG-7-19, Att. at 1). There is no evidence that the increase in these accounts that occurred during 2009 is abnormal or otherwise unrepresentative of Fitchburg's maintenance expenses. Moreover, when viewed in the context of the Company's total gas O&M distribution expense booked to Accounts 851 through 894, when USC charges are excluded from these accounts the net increase in gas O&M distribution expense is $72,504 (Exhs. Unitil-MHC-Rebuttal-2, at 6; AG-1-34, Att. (gas)). The Department considers this net increase to be consistent with reasonable fluctuations that can be associated with normal business activity from year to year. Accordingly, the Department declines to make an adjustment to normalize test year expenses booked to Accounts 887 and 892.

N. Account 880 – Other Distribution Expenses – Gas Division

1. Introduction

In 2008, Fitchburg booked $137,819 in Account 880 (Other Distribution Expenses) for its gas division (Exh. AG-7-19, Att. at 1 (gas)).[206] During the test year, the Company booked

[206] For gas companies, Account 880 (Other Distribution Expenses) includes the cost of transmission and distribution maps and records, transmission and distribution office expenses, and the cost of labor and materials used and expenses incurred in transmission and distribution system operations not provided for elsewhere, including the expenses of operating street lighting systems. See 220 C.M.R. § 50.00 et seq.

$685,835 to that same account (Exh. AG-7-19, Att. at 1 (gas)). The Company states that the $548,016 difference is attributable to the fact that several Fitchburg employees were transferred in 2009 to USC, thereby increasing the Company's outside services expense (Exh. AG-7-19, Att. at 1 (gas)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has not sufficiently explained or justified the increase of approximately $548,000 in USC expenses charged to Account 880 (Attorney General Brief at 57-58; Attorney General Reply Brief at 29). The Attorney General contends that, if Fitchburg's explanation for the change in account balance is correct, such an increase in charges from USC should be offset by a comparable reduction in Fitchburg's payroll expense, leaving no net increase (Attorney General Brief at 57-58, citing Exh. AG-DJE-1, at 10 (gas)). The Attorney General claims, however, that there were no offsetting reductions to the Company's direct payroll expense and that the Company has failed to identify any new services being provided by USC that would require such an increased level of expenses (Attorney General Brief at 57-58). As such, the Attorney General recommends that the increased charges to the Company's gas Account 880 be eliminated from Fitchburg's cost of service (Attorney General Brief at 59).

b. Fitchburg

Fitchburg argues that the increase in USC charges recorded in its gas Account 880 are the result of the creation of a centralized gas distribution management and operations function at USC (Company Brief at 66, citing Exh. Unitil-MHC-Rebuttal-2, at 7). In particular, the Company contends that the cost increases are associated with the filling of previously open positions at Fitchburg and the transfer of active Fitchburg employees to USC (Company Brief at 66, citing Exh. Unitil-MHC-Rebuttal-2, at 7). The Company claims that the increase in Account 880 was offset by a corresponding decrease in costs Fitchburg would have incurred had it filled the aforementioned open positions and continued to staff the transferred job functions locally (Company Brief at 66, citing Exh. Unitil-MHC-Rebuttal-2, at 7). Further, the Company argues that because Fitchburg's payroll expenses are also affected by inflationary increases on its remaining employees, it is not reasonable to expect a dollar-for-dollar tradeoff between USC and Fitchburg when employees are transferred (Tr. 13, at 1726).

3. Analysis and Findings

The Department typically includes a test year level of expenses in cost of service and will adjust this level for known and measurable changes to the test year. D.P.U. 87-260, at *75;* D.P.U. 1270/1414, at 33. The issue before the Department is whether Fitchburg has adequately justified an increase to its cost of service associated with O&M Account 880 for its gas division as a known and measurable change to test year cost of service.

A number of employee positions were transferred from Fitchburg to USC post-test year in 2009 in order to establish a centralized or shared service gas dispatch and nominations group as part of an effort to reduce costs across the entire system (Tr. 7, at 793). All else equal, an offsetting adjustment to Fitchburg's payroll expense should result from a transfer of employees. However, the approximate $548,000 increase to Account 880 represents not only salary and wages, but all benefits and other overheads (Tr. 17, at 2278-2279). Thus, even if the transfers did not take place, there is no one-to-one relationship between the respective accounts.

The Company has adequately accounted for four positions that were transferred from USC to Fitchburg: (1) a gas operations director; (2) a gas dispatch manager; (3) a gas controller; and (4) an electric systems operator (RR-DPU-65). Further, two gas controller positions that were previously held open at Fitchburg in 2008 were transferred to USC (RR-DPU-65). The four positions that were transferred from USC to Fitchburg have salaries and wages that total $286,000 (RR-DPU-65). As noted above, the increase to Account 880 represents, in addition to salary and wages, all benefits and overheads (Tr. 17, at 2278-2279). According to the Company, a loading rate of approximately 100 percent is required to fully account for the benefits and overheads associated with these positions (Tr. 17, at 2279). The proposed increase to Account 880 of $548,000 represents a loading rate of approximately 92 percent. Accordingly, the Department finds that the Company has sufficiently justified the increase in USC expenses charged to Account 880 as known and measurable.

O. Proposed Vegetation Management Program

1. Fitchburg's Proposal

The Company's test year distribution tree trimming expenditure was $292,691 (Exh. Sch. RevReq-7-14 (Supp. 3) (electric)).[207] The Company requests a total of $1,602,200

[207] The Company's total test year tree trimming spending was $578,826 (Exh. Sch. RevReq-7-14 (Supp. 3) (electric)). The Company adjusted this amount by subtracting $84,135 for transmission tree trimming and $202,000 for capitalized expenses, resulting in the test year distribution tree trimming expenditure of $292,691 (Exh. Sch. RevReq-7-14 (Supp. 3) (electric)).

annually to implement proposed changes to its vegetation management program ("VMP"), which results in a pro forma adjustment of $1,309,509 over test year VMP expenses (Exh. Sch. RevReq-7-14 (Supp. 3) (electric)).[208] As directed by the Department in D.P.U. 09-01-A at 213, the Company hired a consultant to assess the Company's existing vegetation management program and advise it on appropriate vegetation management practices going forward (Exh. Unitil-TPM-1, at 17-18 (electric)). Following a competitive solicitation, the Company retained Environmental Consultants, Inc. ("ECI") to evaluate the Company's distribution and sub-transmission VMP (Exh. Unitil-TPM- 1, at 17-18 (electric)). In June 2010, ECI completed a report ("ECI Report") that made recommendations for improving the Company's vegetation management practices (Exh. Unitil-TPM-1, at 18 (electric); Tr. 19, at 2622)).

The primary purpose of the ECI study was "to identify an optimal vegetation management strategy for the entire Unitil-FG&E distribution and sub-transmission system and project associated budgets and reliability improvements" (Exh. Unitil-EC/AP-2, at 1-1 (electric)). The ECI Report makes two principle recommendations: (1) shorten trimming

[208] The Company initially requested a total of $1,652,200 to implement the proposed VMP, which results in a pro forma adjustment of $1,359,509 (Exhs. Unitil-MHC-1, at 35 (electric); Sch. RevReq-7-14 (electric)). It subsequently updated the pro forma adjustment to allocate $50,000 from transmission to distribution, and requests a total of $1,602,200 for costs to implement the distribution VMP (Company's Brief at 32 n. 10, citing Exh. Sch. RevReq-7-14 (Supp. 2) (electric)).

cycles and increase clearance standards on distribution circuits; and (2) implement a more aggressive hazard tree removal program (Exh. Unitil-EC/AP- 1, at 4 (electric)). The Company estimated that its SAIDI minutes and SAIFI interruptions would improve by *23.5* percent and 23 percent, respectively, after implementing the proposed changes for one full vegetation management cycle (seven years) (Exh. DPU-22-19 (electric)). The cost of executing these recommendations is $1,602,200 annually, which consists of $650,000 for shorter trimming cycles and enhanced clearances, $780,000 for hazard tree removal,[209] and $172,200 for VMP staffing (Exhs. Unitil-EC/AP-1, at 23-24 (electric); Unitil-EC/AP-2, at 4-28 (electric); Sch. RevReq-7-14 (Supp. 3) (electric)).

2. Attorney General's Proposal

The Attorney General proposes two changes to the VMP proposal put forth by the Company. First, the Attorney General proposes that the Department reduce the Company's VMP annual budget from the initially requested $1,652,200 to $1,065,000 (Exh. AG-HWS-1, at 10 (electric)). The reduction comes primarily from two areas: (1) a less aggressive hazard tree removal program; and (2) the removal of the $172,200 of VMP payroll expenses (Exh. AG-HWS-1, at 11 (electric)).[210]

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209 The ECI Report includes recommended budgets for three periods of VMP implementation, (1) years one through three, (2) years four through ten, and (3) years eleven through 14 (Exh. Unitil-EC/AP-2, at 4-28 (electric)). The Company's requested spending levels are based on the ECI Report recommended budgets for years one through three.

210 In addition, the Attorney General proposes a $10,000 annual decrease in spending on the Company's tree trimming activities in budget years eleven through 14 because she claims that less tree trimming will be needed after an initial catch-up period in early years (Exhs. AG-HWS-1, at 11 (electric); Unitil-EC/AP-2, at 4-28)).

The Attorney General proposes that the Department reduce the Company's hazard tree removal program budget from $780,000 per year to $425,000 per year for the first three years that the VMP is implemented (Exh. AG-HWS-1, at 11 (electric)). The Attorney General argues that the Company can implement a less aggressive hazard tree removal program than that recommended in the ECI Report because many hazard trees have already been removed as a result of Winter Storm 2008 (Exhs. AG-DO-CF-1, at 24 (electric); AG-HWS-1, at 11 (electric); Tr. 19, at 2532). The Attorney General bases her proposed hazard tree budget on the ECI Report's recommended spending levels both in the early years of implementation of the program ($780,000) and the later years of its implementation ($50,000) (Exhs. AG-DO-CF-1, at 24 (electric); AG-HWS-1, at 11 (electric)). The Attorney General states that her proposed $425,000 budget will allow the Company to implement a modest enhanced hazard tree removal program (Exhs. AG-DO-CF-1, at 24 (electric); AG-HWS-1, at 11 (electric)).

The Attorney General proposes that the Department evaluate whether the Company has adequately addressed its hazard tree problem after three years of implementing the program (Exh. AG-HWS-1, at 11 (electric)). The Attorney General further proposes that the Department disallow payroll and benefits cost of $172,200 associated with employing a local vegetation management coordinator and a full-time arborist for the Company's system (Exh. AG-HWS-1, at 6, 11 (electric)). According to the Attorney General, the vegetation management budget should include only direct costs associated with the vegetation management process, and should exclude payroll and benefits costs (Exh. AG-HWS-1, at 6 (electric)). The Attorney General contends that allowable payroll and benefits costs for vegetation management staff should be included in another base rate category provided that the Department deems the cost justified (Exh. AG-HWS-1, at 11 (electric)).

The Attorney General proposes that the Department condition our approval of her proposed $1,065,000 VMP budget on the requirement that the Company expend the full amount annually (Exh. AG-HWS-1, at 10 (electric)). She argues that the Company be required to annually report to the Department and the Attorney General the amount of VMP allowance budgeted but not expended (Exh. AG-HWS-1, at 10 (electric)). The Attorney General proposes that if the Company fails to spend the full budgeted amount in a year, the Department should require the Company to apply VMP costs in the following year to the previous year's unexpended balance before expensing those costs against the current year's VMP allowance (Exh. AG-HWS-1, at 10 (electric)).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company's requested tree trimming budget of $1,652,200[211] per year is excessive (Attorney General Brief at 130). She argues that this

[211] The Attorney General cites to the Company's initially requested VMP budget rather than to the Company's reduced request of $1,602,200 (see Attorney General Brief at 130).

amount is over five times the test year vegetation management expense of $292,691 (Attorney General Brief at 130, citing Exh. AG-HWS-1, at 5 (electric)). The Attorney General contends that conditional approval of a decreased VMP budget of $1,065,000 will protect ratepayers in the event the Company fails to spend the tree trimming allowance (Attorney General Brief at 130, 135-136).

Additionally, the Attorney General asserts that Winter Storm 2008 and the subsequent restoration work removed many hazard trees and overhanging limbs (Attorney General Brief at 131). As a result of the clean up that occurred on its system during the Storm and the restoration, the Attorney General asserts that the Company's hazard tree removal budget should be reduced (Attorney General Brief at 131).

The Attorney General also claims that the Company's past vegetation management practices were insufficient (Attorney General Brief at 132-133). The Attorney General argues that by adopting its previous VMP the Company adopted certain standards for vegetation management that corresponded to the level of need on its system (Attorney General Brief at 132, citing Exh. AG-HWS-1-Rebuttal, at 2-3; Tr. 18, at 2445). The Attorney General argues that the Company subsequently failed to follow its own standards, and claims that this contributed to the damage caused by the Storm and resulted in the Company's failing to provide reliable service to its customers (Attorney General Brief at 133).

The Attorney General contends that once the Company spends more on vegetation management, it will incur decreased costs associated with three key parameters that drive the cost-effectiveness of a VMP program: (1) tree density; (2) cost per tree; and (3) hot spotting, which is trimming in response to trouble calls (Attorney General Brief at 131). This, in turn, will reduce the necessary cost of tree trimming (Attorney General Brief at 131). Accordingly, the Attorney General argues that there should be a mechanism to reduce the VMP budget as the system becomes more manageable (Attorney General Brief at 131-132).

Finally, the Attorney General objects to the Company's request for an automatic adjustment mechanism that accounts for spending overruns and underruns (Attorney General Reply Brief at 13). Rather, the Attorney General argues that unexpended funds should be refunded[212] or used the following year (Attorney General Reply Brief at 13, citing Company Brief at 36).

b. DOER

DOER does not take a position with respect to the appropriate level of spending for vegetation management (DOER Brief at 7 (electric)). DOER argues, however, that an appropriate level should be included in rates and any unspent dollars should accrue as a credit to rates unless the Company expends those amounts in subsequent years (DOER Brief at 7-8 (electric)). DOER contends that the Company should be required to report its VMP expenditures in its next rate case (DOER Brief at 8 (electric)). DOER recommends that, at that time, the amount of the allowed vegetation management budget not spent should be credited to customers (DOER Brief at 8 (electric)).

[212] The Attorney General did not include refunding unexpended funds to ratepayers as part of its vegetation management proposal (see AG-HWS-1, at 10 (electric)).

c. Fitchburg

The Company asserts that ECI's recommendations are the result of a thorough and detailed analysis of the system work load and evaluation of tree re-growth by species (Company Brief at 33, citing Exh. Unitil-EC/AP-1, at 22 (electric)). The Company contends that ECI's two primary recommendations are to: (1) expand and formalize the Company's existing vegetation management practices to address the specific vegetation conditions on its system; and (2) implement a more aggressive and systematic removal of hazard trees from its system (Company Brief at 33, citing Exh. Unitil-EC/AP-1, at 4, 27 (electric)). The Company asserts that implementing the new VMP will improve overall system reliability as well as reliability during typical weather events (Company Brief at 34, 35).

The Company claims that it did not immediately implement the proposed VMP because it was strictly complying with the Department's Order in D.P.U. 09-01-A at 160 (Company Brief at 36-37). The Company asserts that because, in D.P.U. 09-01-A at 160, the Department directed it to submit a revised VMP and policy to the Department for review, the Company had no option but to allow the Department to review the VMP before implementing the program (Company Brief at 36-37).

The Company does not object to the Attorney General's proposed calculation for allowable VMP expense, but states that her proposed expense is not sufficient to optimally implement the ECI Report's recommendations (Company Brief at 36). The Company also does not object to creating a conditional allowance for the VMP expenses, but argues that any mechanism would need to be symmetrical and account for both cost overruns and underruns from year to year (Company Brief at 36).

4. Analysis and Findings

It is a well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. See D.P.U. 10-70, at 232, 254-255; Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3-5 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4-5 (1975); New England Telephone and Telegraph Company, D.P.U. 18210, at 2-3 (1975); see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to G.L. c. 164, § 94, the Department examines a test year that usually represents the most recent twelve-month period for which complete financial information exists. D.P.U. 10-70, at 232. The basis for this ratemaking principle is that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation and fairly represent its cost to provide service. D.P.U. 10-70, at 232; Ashfield Water Company, D.P.U. 1438/1595, at 3-4 (1984). The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. See D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (1984).

The Company's test year expenditure on VMP was $292,691 (Exh. Sch. RevReq-7-14 (Supp. 3) (electric)). This amount is comparable to the Company's vegetation maintenance expenditure over the past 15 years, in which the Company spent between $181,000 and $328,000 annually (Exh. *AG-22-5*, Att. (electric)). There is nothing in the record to suggest that the test year expenditure was not an accurate representation of the Company's historic vegetation maintenance spending, and we find that the test year expenditure is representative of the Company's spending on vegetation maintenance.

Although the ECI Report detailing the proposed VMP changes was completed in June 2010, the Company did not immediately implement the proposed VMP (Tr. 19, at 2622-2623). The Company argues that it did not immediately implement the proposed VMP because it was complying with the letter of the Department's Order in D . P. U. 09-01-A, in which we directed the Company "to report to the Department on a monthly basis and submit a revised vegetation management program and policy for Department review" (Company Brief at 36-37, citing D.P.U. 09-01-A at 160). The Order, however, in no way prohibited the Company from implementing a revised VMP before Department review, nor did we specify that Department review should occur within the context of a rate case. See D.P.U. 09-01-A at 160, 213. Additionally, the Company did not inform the Department it would not be implementing any of the recommended provisions of the Report unless and until it obtained favorable rate treatment. Further, the Department's Order also directed the Company to report on a monthly basis concerning the progress of implementing a new and improved vegetation management program and policy. D.P.U. 09-01-A at 213. We do not find the Company's explanation for failing to implement its proposed VMP in advance of this case compelling.

Moreover, the Company testified that financial considerations were a factor in delaying implementation of the new program (Tr. 19, at 2622-2623). We note that the Company has an overriding public service obligation to ensure that it expends sufficient funds on VMP to ensure reliability on its system.

The Company's requested post-test year adjustment is based solely on the estimated costs reflected in the ECI Report rather than historic test year expenses. The Company has failed to adequately fund its vegetation maintenance activities in the past, as evidenced by its failure to keep up with trimming cycles and the high number of trees in close proximity to conductors (Exhs. AG-HWS-1, at 8 (electric); Unitil-EC/AP-2, at 1-6 (electric)).[213] In addition, between 1998 and 2010 the Company failed to spend its budgeted vegetation maintenance funding in all but two years (Exh. AG-22-5, Att. (electric)). Although the Company represents that its goal is to implement ECI's recommendations if sufficient funding is available (Tr. 11, at 1389-1390), the Company's historic failure to meet tree trimming cycles and to expend budgeted funds to perform vegetation maintenance provides the Department with little confidence that VMP funds would be fully expended if the Department put them into base rates. Our concern that the Company would not spend the additional funds on its VMP is exacerbated by testimony from both the Company and the Attorney General that

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213 Moreover, the Department found that the Company underfunded its vegetation management budget on its distribution system and fell behind its prescribed tree trimming schedule in the seven years before the Storm. D.P.U. 09-01-A, Exhs. DPU-1-6, Att. 1; AG-1-1, at 1 & Att. 1; AG-2, at 8; AG-4-101, at 1. At the end of 2008, Unitil was 18 to 21 months behind schedule for distribution system vegetation management. D.P.U. 09-01-A at 159, Exh. DPU-1-6, Att. 1.

utilities often fail to meet cycle trimming goals, and often reduce vegetation management spending to achieve earning targets or account for other budget shortfalls (Exh. AG-DO-CF-2-Rebuttal, at 4-5 (electric); Tr. 18, at 2342-2346; Tr. 19, at 2547-2548, 2610-2611). Given the Company's poor record with respect to funding its vegetation maintenance program and expending budgeted funds, the Department concludes that ratepayers would bear an unwarranted risk if the Department approves the Company's request to put the proposed VMP funds into base rates. Accordingly, because the proposed VMP has not been implemented and the Department has no assurance that the funds will be expended, we conclude that the proposed post-test year change does not constitute a known and measureable change that permits an adjustment.

Alternatively, the Department could conditionally approve the VMP funds by creating a new reconciling mechanism in which the Company's annual expenditures on VMP would be tracked and reconciled. Recent years have seen the proliferation of reconciling mechanisms, including mechanisms for decoupling, targeted infrastructure replacement, capital expenditures, Attorney General consultant costs, pension/post-retirement benefits other than pension, residential assistance, and supply-related bad debt. D.P.U. 10-70, at 160-161; D.P.U. 09-39, at 61, 81-82, 85; D.P.U. 09-30, at 104-105, 117, 134, 407-408; D.P.U. 07-50-A at 31-34; Investigation to Increase the Participation Rate for Discounted Electric, Gas and Telephone Service, D.T.E. 01-106-C/D.T.E. 05-55/D.T.E. 05-56, at 14 (2005); Costs to be Included in Default Service, D.T.E. 03-88-F at 4, 6 (2005);

Commonwealth Electric Company/Cambridge Electric Light Company/Boston Edison Company, D.T.E. 03-47-A, at 30-33 (2003). The Department has stated that we will give careful consideration to the formation of any new fully reconciling cost mechanism. D.P.U. 10-70, at 48, citing D.P.U. 10-55, at 66 n.43. Specific criteria the Department considers when determining whether to allow a new fully reconciling mechanism include whether the cost is: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control. D.P.U. 10-70, at 48, citing D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186; D.T.E. 03-47-A, at 25-28, 36-37; Eastern Enterprises and Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998).

The Department concludes that vegetation management costs are neither volatile nor outside the Company's control. A volatile expense is one that varies significantly based on a fluctuating stock market, changing interest rates, or other economic circumstances beyond a company's control. See, e.g., D.T.E. 03-47-A at 19-20. Neither the Company's historic vegetation management expenses nor the increased funding proposed by the Company are indicative of a volatile expenditure (Exhs. Unitil-EC/AP-1, at 5 & n.5 (electric); Sch. RevReq-7-14 (Supp. 3) (electric); AG-22-5, Att. (electric)). Although the proposed VMP funding is a significant increase over past levels, there would be relatively little year-to-year variability that would necessitate a reconciling mechanism (Exh. Unitil-EC/AP-1, at 5 & n.5 (electric)). Further, based upon the discretion afforded the Company to establish its vegetation management goals and budget, and confirmed through evidence that companies often reduce vegetation management spending to achieve earning targets or account for other budget shortfalls, vegetation management practices and associated expenditures are well within Company control (see Exhs. AG-DO-CF-2-Rebuttal, at 4-5 (electric); AG-22-5, Att. (electric); AG-HWS-2 (electric)). Although the proposed vegetation management expense is relatively large and neutral to sales fluctuations, these factors alone provide insufficient justification to create a new reconciling mechanism.

Based on these considerations, the Department concludes that vegetation management expenses are not the type of cost that should be addressed by creating a new reconciling mechanism. Rather, vegetation management is a fundamental distribution utility practice within a company's control that is critical to providing safe and reliable service. It is the Company's duty to ensure that its VMP is sufficiently robust in order to reliably serve customers. The Department is not persuaded that the Company's failure to date to implement a more robust VMP necessitates creating another reconciliation mechanism. Similarly, because the Attorney General's proposal to implement a conditional VMP allowance of $1,065,000 also requires creating another mechanism that would reconcile the annual vegetation management costs, the Department disapproves the Attorney General's proposal.

Based on the above considerations, we deny the Company's proposed post-test year adjustment to its VMP budget. Accordingly, we will reduce the Company's distribution revenue requirement by $1,309,509. We note that, pursuant to the provisions of G.L. c. 164, § 94, the Company may seek rate relief if it deems it necessary in order to recover future costs associated with VMP efforts that are required to meet its public service obligations.

The Department's denial of the Company's proposed post-test year adjustment does not in any way obviate the Company's obligation to provide safe and reliable service to its customers. The Company remains responsible for assessing the recommendations included in the ECI Report, and implementing those recommendations that it deems necessary to improve its VMP and ensure reliability.[214] For example, the ECI Report projects that adopting the recommendations would improve the Company's performance regarding one of the Department's reliability service quality standards, SAIFI, by 23 percent (Exh. DPU-22-19 (electric)). The Department notes that the Company's performance benchmark for SAIFI (1.697)[215] currently is the highest among Massachusetts electric utilities, and that the projected level of improvement projected by ECI would bring the Company's SAIFI performance on par

214 The Department does not intend to provide programmatic review and approval of the Company's proposed VMP. Rather, the purpose of the Department's directive in D.P.U. 09-01-A at 160 to submit the vegetation management report for our review was to provide the Department with the results of ECI's evaluation and ensure us that the Company had sufficient information available to take appropriate steps to develop and implement an adequate VMP. The Department does not traditionally manage the Company's VMP practices. It remains in the Company's discretion to implement specific recommendations included in the ECI Report to fulfill its obligation to provide safe and reliable service.

215 See Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 11-SQ-10, 2010 Service Quality Report at 9. This matter is pending before the Department.

with other utilities.[216] Therefore, the Department fully expects the Company to implement all changes to its existing VMP required to maintain or improve system reliability and safety.

P. Major Storm Reserve Recovery Mechanism

1. Introduction

The Company proposes to implement a storm reserve recovery mechanism ("storm fund") (Exh. Unitil-MHC-1, at 35). Fitchburg proposes to establish an annual funding level for the storm fund by increasing its annual operating expense in the amount of $200,000, to be accrued at an equal monthly rate up to a maximum balance of $1,000,000 (Exh. Unitil-MHC-1, at 35-36 (electric); Tr. 13, at 1672). Under its proposal, the Company would be allowed to access the storm fund when its costs of responding to an individual storm, including pre-storm preparation costs, exceed $50,000 (Exhs. Unitil-MHC-1, at 35-36 (electric); DPU-4-2 (electric)).

To the extent the storm fund is in a surplus or deficit position, the Company proposes that interest would accrue or be charged at the customer deposit rate (Exh. Unitil-MHC-1, at 36 (electric)). The proposed storm fund cap of $1,000,000 would apply to both positive and

[216] SAIDI/SAIFI mean benchmarks for all companies are based on data collected between 1996 and 2005. SAIFI mean benchmarks for other electric distribution companies are as follows: (1) Massachusetts Electric Company – 1.254; (2) Nantucket Electric Company – 0.426; (3) NSTAR Electric Company – 1.217; (4) WMECo – 1.001. Massachusetts Electric Company d/b/a National Grid, D.P.U. 11-SQ-10, 2010 Service Quality Report, Section 2, at 1; Nantucket Electric Company d/b/a National Grid, D.P.U. 11-SQ-12, 2010 Service Quality Report, Section 2, at 1; NSTAR Electric Company, D.P.U. 11-SQ-13, 2010 Service Quality Report, Sch. 1, at 1; Western Massachusetts Electric Company, D.P.U. 11-SQ-14, 2010 Service Quality Report, Form B at 1. These matters are also pending before the Department.

negative balances (Tr. 13, at 1672). If the balance of the proposed storm fund becomes negative as of December 31st of any year because the Company has withdrawn the entire storm fund to respond to major storms, the Company proposes to recover the amount needed to bring the storm fund balance back to zero through its RDM adjustment, subject to the annual recovery cap of $1,000,000 (Exh. Unitil-MHC-1, at 36 (electric)).

The Company states its proposed annual funding level of $200,000 for the storm fund is based on: (1) its O&M expenses associated with Winter Storm 2008; (2) new major storm-related costs that are associated with pre-storm planning and staging costs; and (3) other major storm costs that the Company incurred in recent years (Exh. Unitil-MHC-1, at 36-37 (electric)). Further, Fitchburg states that in developing its proposed funding level, it considered data from WMECo, National Grid's electric operations, and Public Service Company of New Hampshire ("PSNH") as these entities are located in the same area of New England and all four companies incurred significant costs to restore service after Winter Storm 2008 (Exh. Unitil-MHC-1, at 36 (electric)).

2. Positions of the Parties

a. Attorney General

The Attorney General supports the implementation of a storm fund for Fitchburg but argues that the Department should allow an annual storm fund accrual of only $100,000 and not $200,000 as proposed by the Company (Attorney General Brief at 138). The Attorney General takes issue with the Company's method of setting the storm fund balance based on a comparison of data from WMECo, National Grid's electric operations, and PSNH

(Attorney General Brief at 137-138, citing Exh. Unitil-MHC- 1, at 36-37 (electric)). The Attorney General claims that any comparison to National Grid and PSNH is not suitable because of size differences relative to Fitchburg (Attorney General Brief at 138). Instead, she argues that only WMECo should be used for comparison in making the Department's determination of the appropriate annual storm fund accrual (Attorney General Brief at 138).

Further, the Attorney General argues the Company erred by basing its proposed annual storm fund accrual on the average reserve per megawatt-hour sales and average amount of reserve to revenue from electric sales, neither of which she contends has any correlation to storm costs (Attorney General Brief at 138). Instead, the Attorney General argues that a more appropriate factor to use to develop its storm fund accrual would be the number of system miles because this factor has a greater correlation with potential storm damage (Attorney General Brief at 138).

Using WMECo's annual storm reserve costs per mile of distribution system, the Attorney General calculates an annual storm fund requirement for Fitchburg of $84,310 (Attorney General Brief at 138, citing Exh. AG-HWS-1, at 3-4).[217] The Attorney General notes that using WMECo's annual storm reserve costs per customer results in an even lower annual storm fund requirement of $80,166 (Attorney General Brief at 138,

[217] The Attorney General states that WMECo's annual storm reserve is equal to approximately $168.62 per mile, which, when multiplied by Fitchburg's 500 miles of distribution system, results in a reserve requirement of $84,310 for Fitchburg (Attorney General Brief at 138, citing Exhs. AG-HWS-1, at 3-4; AG-10-6 (electric)).

citing Exh. DPU-4-1, Att.) (electric)).[218] Nevertheless, the Attorney General recommends setting the annual funding level of Fitchburg's storm fund at $100,000 as she contends that this level is reasonable based on both cost per mile and cost per customer (Attorney General Brief at 138-139).

b. Fitchburg

Fitchburg contends that the costs it incurs to respond to major storms have increased dramatically in recent years (Exh. Unitil-MHC-1, at 35). Nevertheless, the Company argues that, unlike other electric utilities operating in Massachusetts, it does not currently have a mechanism to recover the costs of major storms outside of a rate case (Company Brief at 53, citing Exh. Unitil-MHC-1, at 35 (electric)).

Fitchburg maintains that its proposed annual funding level of $200,000 for its storm fund is consistent with the storm funds of WMECo, National Grid's electric operations, and PSNH, scaled to reflect the size of the Company relative to the other three companies (Company Brief at 53). The Company argues that the Attorney General's recommended annual funding level of $100,000 is not reasonable because her analysis involves only a comparison to data from WMECo (Company Brief at 80).

218 The Attorney General states that WMECo's annual storm reserve is equal to approximately $2.82 per customer, which, when multiplied by Fitchburg's customer count of 28,472, results in a reserve requirement of approximately $80,166 for Fitchburg (Attorney General Brief at 138, citing Exh. DPU-4-1, Att. (electric)).

3. Analysis and Findings

When a major storm occurs, a company may have to spend considerable funds to restore service. See D.P.U. 09-39, at 205. Under traditional Department ratemaking practice, if the test year level of storm-related expense is not extraordinary in relation to the company's distribution revenues, the cost of service would include the full amount of the expense. Western Massachusetts Electric Company, D.P.U. 558, at 26-27 (1981); Boston Edison Company, D.P.U. 19991, at 28 (1979). Alternatively, if the test year expense is extraordinary, the Department may permit the expense to be amortized over a period of years.[219] D.P.U. 1720, at 89; D.P.U. 85-266-A/85-271/A at 95-98; Boston Edison Company, D.P.U. 19300, at 36 (1978). Under this ratemaking treatment, the risk of unanticipated expenses such as extraordinary storm costs is shared by both shareholders and ratepayers. The Department has elected to permit extraordinary nonrecurring expenses to be recovered over time as a way to insulate the Company from business risk resulting from large, unanticipated expenditures. The Department does not intend, in so doing, to shift the risk of unanticipated expenses solely to the ratepayers. D.P.U. 1720, at 89.

[219] A company may seek approval to defer the costs associated with its response to a major storm to allow it to request recovery for that expense in the company's next rate case even though that expense was incurred before the test year used in that proceeding. For approval, the company must demonstrate that: (1) based on Department precedent, the annual expense might be recoverable as an extraordinary expense if it were incurred during a test year; (2) a Department denial of the request for deferral would significantly harm the 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. 09-61, at 8; D.P.U. 93-229, at 7.

In recent years, the Department has departed from this past regulatory practice and, in the context of rate settlements, approved storm funds for various electric distribution companies.[220] The Department has found that, if a storm fund is properly designed, it has the potential to benefit both a company and its customers by levelizing the cost effects of major storms on distribution rates. D.P.U 10-70, at 196-197; D.P.U. 09-39, at 206. Under a storm fund, revenues are collected for extraordinary storms in advance through rates and are placed in a storm contingency account. When an extraordinary storm occurs, the company may recover a portion of the incremental costs to restore service from the reserve in the storm contingency account. With a storm fund, essentially all of the financial risk of storm costs is born by ratepayers because the company receives dollar for dollar recovery of the costs it incurs to respond to the storm.

The Department gives careful consideration to the formation of any new cost reconciling mechanisms. See, e.g., D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186; D.T.E. 03-47-A, at 25-28, 36-37; D.T.E. 98-27, at 6, 28. Such consideration is warranted because cost recovery mechanisms can lessen the incentive of a utility to control its costs.

[220] The Department has approved rate settlements for a number of electric distribution companies that include storm funds. See, e.g., Western Massachusetts Electric Company, D.T.E. 06-55, at 7-8, 21-22 (2006); Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, D.T.E. 05-85, at 7-8, 31-32 (2005); Boston Edison Company, D.P.U./D.T.E. 96-23, at 70 (1998). In addition, the Department has approved modifications to storm funds that were previously approved as part of rate settlements. See D.P.U. 10-70, at 196-201; D.P.U. 09-39, at 205-213.

Under traditional ratemaking practice, there is a time gap between when a utility incurs a cost and when the utility can account for the change in costs through new rates. This time gap is referred to as “regulatory lag” and it provides a strong incentive for companies to control costs and to invest in capital wisely. See D.P.U. 09-39, at 80. Cost reconciling mechanisms, because they allow dollar for dollar recovery from ratepayers, substantially reduce, or in some cases may eliminate, any benefits to ratepayers associated with regulatory lag.

Fitchburg does not currently have a storm fund. Fitchburg claims that its major storm response costs have dramatically increased and a storm fund is needed to address the negative impact of these costs on customers and the Company (Exh. Unitil-MHC-1, at 35).[221] However, in light of the Company’s poor performance restoring service to customers in the aftermath of Winter Storm 2008,[222] for the reasons discussed below, we find that it is not in the public interest to approve a storm fund for Fitchburg at this time.

In D.P.U. 09-01-A, the Department identified a multitude of deficiencies in the Company’s preparation for and response to Winter Storm 2008. The Department found that the Company’s planning and training for a major storm event was a primary contributor to its unacceptable performance. D.P.U. 09-01-A at 47. The Department also found that the Company underfunded its vegetation management budget and fell behind on its tree trimming schedule in the year prior to Winter Storm 2008. D.P.U. 09-01-A at 159. Further, in

[221] The Company’s test year storm and unscheduled maintenance spending totaled $271,128 (Exh. AG-3-27, Att. (electric); RR-DPU-72).
[222] See Section V above.

D.P.U. 09-01-A at 47, the Department found that the Company's failure to properly plan and prepare for storm events resulted in: (1) its inability to restore service to its customers in a timely manner; (2) its failure to communicate accurate and useful information to the public; and (3) its failure to coordinate its restoration efforts with local public safety officials.

In light of Fitchburg's management deficiencies in its response to Winter Storm 2008, we are not convinced that it can manage storm costs efficiently. If left unchecked, subpar management performance can translate to higher cost of service and can lead to higher rates for customers. The regulatory lag inherent in the Department's traditional ratemaking treatment of major storm costs is one important tool to ensure that costs are controlled.

Fitchburg must demonstrate a record of improved performance before it is allowed the greater discretion with ratepayer funds that comes from a storm fund mechanism. Under these circumstances, we find that it is not appropriate to shift the risk of unanticipated storm expenses solely to the Company's ratepayers. Therefore, given Fitchburg's recent history of demonstrated subpar management performance, we find it is in the public interest for us to continue our traditional ratemaking treatment of major storm costs as a means to encourage Fitchburg's management to control costs.

Based on these considerations, the Department declines to approve a storm fund for Fitchburg at this time.[223] Through our traditional regulatory treatment of such costs, we find

[223] As we have declined to approve a storm fund for Fitchburg at this time, we need not address whether the Company has appropriately justified an annual funding level of $200,000 or a threshold level of $50,000. We note, however, that the Company historically has not tracked its storm-related expenses separately from other emergency repair and unscheduled maintenance work (Exh. AG-3-27 (electric)). If the Company seeks to implement a storm fund in the future, it must be prepared to identify historical spending associated solely with storms, so as to support its request for an appropriate annual funding level.

Fitchburg will have an adequate opportunity to seek recovery of its prudently incurred storm costs. Accordingly, the Department will remove $200,000 from the Company's cost of service.

XI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

The Company calculates a WACC of 8.50 percent representing the rate of return to be applied on rate base to determine the Company's total return on its investment (see Exhs. Unitil-MHC-1, at 42-43 (electric); Sch. RevReq-13 (Supp. 3) (electric); UnitilMHC-1, at 31-32 (gas); Sch. RevReq-12 (Supp. 3) (gas); Unitil-SCH-Rebuttal-1, at 1).[224] This WACC is based on a proposed capital structure of 55.70 percent long-term debt, 1.40 percent preferred stock, and 42.90 percent common equity (Exhs. Unitil-MHC-1, at 43 (electric); Sch. RevReq-13 (Supp. 3) (electric); Unitil-MHC-1, at 32 (gas); Sch. RevReq-12 (Supp. 3) (gas)). In addition, the Company proposes a cost of long-term debt of 6.99 percent, a cost of

[224] As discussed below, Fitchburg revised its proposed ROE during the proceedings, which results in a reduction to the WACC. However, the Company did not update its schedules to take into account its revised ROE (see, e.g., Exhs. Sch. RevReq-13 (Supp. 3) (electric); Sch. RevReq-13 (Supp. 3) (gas)). Consequently, Fitchburg's schedules and briefs continue to reference the original WACC of 8.58 percent (see, e.g., Company Brief at 81). Substituting the Company's revised ROE of 10.5 percent for its initially proposed ROE of 10.7 percent produces a WACC of 8.50 percent.

preferred stock of 6.74 percent, and an ROE of 10.50 percent (Exhs. Unitil-MHC-1, at 43 (electric); Unitil-SCH-Rebuttal-1, at 1; Sch. RevReq-13 (Supp. 3) (electric); Unitil-MHC-1, at 32 (gas); Sch. RevReq-12 (Supp. 3) (gas)).[225]

In determining its proposed ROE, the Company relied on the discounted cash flow ("DCF") model and the risk premium model (Exhs. Schs. SCH-4 and SCH-5 (electric); Schs. SCH-4 and SCH-5 (gas)). These models were applied to market and financial data developed from a proxy group of gas and electric distribution companies (Exhs. Schs. SCH-4 and SCH-5 (electric); Sch. SCH-Rebuttal-5 (electric); Schs. SCH-4 and SCH-5 (gas); Sch. SCH-Rebuttal-6 (gas)).

The Attorney General calculates a WACC of 7.74 percent for the Company's gas division based on an ROE of 8.75 percent developed using her own gas proxy group (Exh. AG-JRW-1, at 2 (gas)). The Attorney General calculates a separate WACC of 7.96 percent for the Company's electric division based on an ROE of 9.25 percent developed using her own electric proxy group (Exh. AG-JRW-1, at 2 (electric)). We discuss the components of the Company's and the Attorney General's proposals below.

225 In its original petition, the Company proposed an ROE of 10.70 percent (Exhs. Unitil-MHC-1, at 42 (electric); Sch. RevReq-13 (electric); Unitil-MHC-1, at 32 (gas); Sch. RevRev-12 (gas)). On rebuttal, Fitchburg lowered its proposed ROE to 10.50 percent based on updated financial information as of March 1, 2011 (Exh. Unitil-SCH-Rebuttal-1, at 1, 25-26).

B. Capital Structure and Cost of Debt/ Preferred Stock

1. Fitchburg's Proposal

Fitchburg proposes to use its test year-end capital structure as of December 31, 2009 consisting of 55.70 percent long-term debt, 1.40 percent preferred stock, and 42.90 percent common equity (Exhs. Unitil-MHC-1, at 43; Sch. RevReq-13 (Supp. 3) (electric); Unitil-MHC-1, at 32; Sch. RevReq-12 (Supp. 3) (gas)). The Company proposes a rate of 6.99 percent for its long-term debt and 6.74 percent for its preferred stock (Exhs. Unitil-MHC-1, at 43 (electric); Unitil-SCH-Rebuttal-1, at 1; Sch. RevReq-13 (Supp. 3) (electric); Unitil-MHC-1, at 32 (gas); Sch. RevReq-12 (Supp. 3) (gas)).

The Attorney General accepts the Company's proposed capital structure and proposed cost of long-term debt and preferred stock (Attorney General Brief at 158). No other party commented on the Company's capital structure, cost of debt, and cost of preferred stock.

2. Analysis and Findings

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; D.T.E. 01-42, at 17-18. 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 determine the return on rate base for calculating the appropriate debt service and capital costs 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; D.P.U. 1360, at 26-27; Blackstone Gas Company, D.P.U. 1135, at 4 (1982). Adjustments to test year-end capitalization to recognize redemptions, retirements, or issuances of new debt or equity are allowed, provided that they are known and measurable and the proposed issuance or retirement of securities has actually taken place by the date of the Order. D.T.E. 03-40, at 323. 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).

No party objected to the Company's proposed capital structure. There have been no new securities issuances or retirements since the end of the test year. As Fitchburg's existing capital structure is identical to its test year-end capital structure, the Department accepts the Company's proposed capital structure consisting of 55.70 percent long-term debt, 1.40 percent preferred stock, and 42.90 percent common equity.

The Department recognizes that costs associated with the issuance of long-term debt and preferred securities, such as issuance costs, debt discounts, and other amortizations, are necessary operating expenses and are expected to occur from time to time as long-term debt is issued by a company. D.P.U. 10-114, at 294, citing D.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The Department has found that the appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161; Boston Edison Company, D.P.U. 86-71, at 12 (1986).

No party objected to the Company's proposed costs of long-term debt and preferred stock. We find that the Company calculated its cost of long-term debt and preferred stock in a manner consistent with Department precedent. See D.T.E. 01-56, at 97-100. Accordingly, the Department finds that Fitchburg's effective cost of long-term debt is 6.99 percent and that its effective cost of preferred stock is 6.74 percent.

C. Proxy Groups

1. Description of the Company's Proxy Group

Fitchburg is a wholly-owned subsidiary of Unitil Corporation and, therefore, has no public market for its stock. Accordingly, Fitchburg presents its cost of equity analysis using the capitalization and financial statistics of a proxy group of 30 gas and electric companies (Exhs. Unitil-SCH-1, at 3-4 (electric); Unitil-SCH-1, at 3-4 (gas); Unitil-SCH-Rebuttal-1, at 26; Tr. 6, at 598-599).[226] The selected companies used in the Company proxy group: (1) are included in Value Line Investment Surveys ("Value Line"); (2) have bond ratings of at

[226] The Company originally used a proxy group of 33 electric and gas companies (Exhs. Sch. SCH-1 (electric); Sch. SCH-1 (gas)). Fitchburg later removed three companies from its proxy group due to the companies' involvement in merger activities (Exhs. Unitil-SCH-Rebuttal-1, at 26; Sch. SCH-Rebuttal-4).

least triple-B by Standard & Poor’s Financial Services, LLC (“S&P”) or Moody’s Investor Service, Inc. (“Moody’s”); (3) receive at least 70 percent of their revenues from domestic utility sales; (4) have not cut their cash common stock dividend in the past two years; and (5) are not currently involved in merger activities (Exhs. Unitil-SCH-1, at 4 (electric); Sch.SCH-1 (electric); Unitil-SCH-1, at 4 (gas); Sch. SCH-1 (gas); Tr. 6, at 598-599).

2. Description of the Attorney General’s Proxy Groups

The Attorney General presents separate proxy groups for the Company’s electric division and gas division (Exhs. AG-JRW-1, at 10 (electric); AG-JRW-1, at 10 (gas)). The Attorney General’s electric proxy group consists of 29 electric companies (Exhs. AG-JRW-1, at 11 (electric); AG-JRW-4, at 1 (electric)).[227] According to the Attorney General, her electric proxy group receives on average 81 percent of its revenues from regulated electric operations, has an A-/BBB+ bond rating from S&P, and has a current median common equity ratio of 46.4 percent (Exhs. AG-JRW-1, at 11; AG-JRW-4, at 1).

The Attorney General’s gas proxy group consists of eight publicly held gas distribution companies (Exh. AG-JRW-1, at 10 (gas)).[228] In selecting the eight companies for her gas proxy group, the Attorney General set four criteria (Exh. AG-JRW-1, at 10 (gas)). Her

227 The Attorney General’s electric proxy group includes all 29 electric companies from Fitchburg’s original proxy group of 33 companies but excludes the four gas companies included in the Company’s group (Exhs. Sch. SCH-1, at 2-3 (electric); AG-JRW-4 (electric)).

228 The Attorney General’s gas proxy group includes the four gas companies contained in the Company’s original proxy group as well as four additional gas companies (Exhs. Sch. SCH-1, at 2-3 (gas); AG-JRW-4 (gas); AG-JRW-1, at 22 n.1 (gas)).

selected companies: (1) are listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports; (2) are listed as a natural gas utility in the Standard Edition of Value Line; (3) receive at least 50 percent of revenues from regulated gas operations;[229] and (4) have an investment grade bond rating by Moody's and S&P (Exhs. AG-JRW-1, at 10-11 (gas); AG-JRW-4, at 1 (gas)). According to the Attorney General, her gas proxy group also has a median common equity ratio of 49.2 percent (Exhs. AG-JRW- 1, at 11 (gas); AG-JRW-4, at 1 (gas)). The Attorney General adds that her gas proxy group receives 64 percent of its revenues from regulated gas operations and has an A bond rating from S&P (Exh. AG-JRW-1, at 11).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that she has evaluated the return requirements of investors on the common stock of her electric proxy group and gas proxy group (Attorney General Brief at 158; Exh. JRW-Rebuttal-1, at 4-5). Based on her comparison of the electric and gas proxy groups, using five different Value Line risk metrics, the Attorney General contends that the gas proxy group is less risky than the electric proxy group on all metrics (Attorney General Brief at 159; Attorney General Reply Brief at 38; Exhs. AG-JRW-4; AG-JRW-Rebuttal-1, at 5). Therefore, the Attorney General concludes that the gas proxy group should have a lower equity cost rate than the electric proxy group (Attorney General Brief at 159; Attorney General Reply Brief at 38).

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229 The regulated gas revenues of one company in the Attorney General's gas proxy group recently have declined to 48 percent of total revenues (Exh. AG-JRW-1, at 11 n.2 (gas)).

b. Fitchburg

Fitchburg argues that its proxy group is sufficiently large in number to gauge the Company's own comparative risk (Company Brief at 86; Exhs. Uniti-SCH-Rebuttal-1, at 26; Sch. SCH-Rebuttal-4). In contrast, Fitchburg claims that the Attorney General's gas proxy group of eight gas companies is too small in size to be a sufficiently reliable benchmark with which to ascertain Fitchburg's risk relative to this group (Company Brief at 92; Company Reply Brief at 44).

Further, Fitchburg asserts that the vast majority of the business enterprises of the companies in its proxy group are devoted to the regulated gas and electric distribution business and, therefore, the ROE resulting from an analysis of the Company proxy group is appropriate under a standard of comparability for both Fitchburg's gas and electric operations (Company Brief at 86-87).

Finally, Fitchburg argues that the Attorney General exaggerates the differences in risk between gas and electric companies (Company Reply Brief at 44). According to Fitchburg, there is only approximately a ten basis point difference between the ROEs awarded by state utility commission to gas companies as compared to electric companies (Company Reply Brief at 44, citing Tr. 12, at 1528).

4. Analysis and Findings

The Department has accepted the use of a proxy 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; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 95-96. The Department has stated that companies in the proxy group must have common stock that is publicly traded and must be generally comparable in investment risk. D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group that matches the Company in every detail. See D.T.E. 99-118, at 80; Essex County Gas Company, D.P.U. 87-59, at 68 (1987); 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 proxy group, and then provides sufficient financial and operating data to discern the investment risk of the Company in relation to the proxy group. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence on the part of expert witnesses in assembling proxy groups that will produce statistically reliable analyses. See D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. The Department expects parties to limit criteria to the extent necessary to develop a larger as opposed to a narrower proxy group. See D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 87-59, at 68.

We find that Fitchburg and the Attorney General each employed a set of valid criteria to select their respective proxy groups. However, because the Attorney General's gas proxy group is restricted to eight gas companies, we must weigh any statistical limitations associated with the size of this proxy group against the arguably greater comparability of these companies to the Company's gas operations. See D.P.U. 10-55, at 480-482. Further, we find that Fitchburg and the Attorney General each provided sufficient information about their proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Company in relation to the members of the proxy groups. See D.P.U. 09-30, at 307. Therefore, the Department will rely on the proxy groups as a basis to analyze the cost of capital proposals.

As noted above, we will consider the particular characteristics of the Company as compared to the proxy groups when determining an appropriate ROE. For example, the decoupling mechanisms approved by the Department are but one form of a wide range of what are considered revenue stabilization mechanisms that are used by a number of companies in the proxy groups (Exhs. AG-7-1, Att. B at 26, 55, 99, 141, 148, 249 (electric); AG-6-1, Att. B at 26, 55, 94, 141, 148, 249 (gas)). The existence and makeup of such mechanisms must be weighed in analyzing Fitchburg's relative risk. See D.P.U. 10-55, at 482; D.P.U. 09-39, at 348; D.P.U. 09-30, at 308; see also D.P.U. 07-50-A at 72. In addition, some of the holding companies in the proxy groups are also involved in non-regulated businesses beyond electric and gas distribution activities, all else equal, making these companies more risky than the Company.[230] D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 07-71, at 135. Finally, certain of the companies (or their subsidiary operating companies) included in the proxy groups are vertically-integrated companies which arguably bear the additional risk inherent in the ownership of electric generation. See D.P.U. 95-40, at 96; D.P.U. 92-78, at 110. Fitchburg, as a restructured company that owns no generation, does not bear the same risk.

D. Return on Equity

1. Fitchburg's Proposal

a. Introduction

Fitchburg proposes to apply a 10.5 percent ROE for the Company based on the results of two equity cost models: the DCF model and the risk premium model (Exh. Unitil-SCH-Rebuttal-1, at 1).[231] Based on its analyses, Fitchburg determined a range of ROEs of between 9.8 and 10.5 percent using the DCF model and between 10.4 and 10.7 percent using the risk premium model (Exhs. Unitil-SCH-Rebuttal-1, at 1; Sch. SCH-Rebuttal-4, at 1; Sch. SCH-Rebuttal-5, at 1-2 (electric)).

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[230] For example, one company in the proxy groups has an energy management services subsidiary that engages in coal mining and oil exploration; another company has various non-utility operations; and another company is engaged in natural gas brokering, along with the sale of gas-fired heating equipment and propane (Exhs. AG-7-1, Att. A, at 6, 7, 11, 22 (electric); AG-6-1, Att. B (gas)).

[231] Fitchburg updated its DCF and risk premium models based on economic and financial data available through March 2011 (Exh. Unitil-SCH-Rebuttal-1, at 25).

b. Financial Models

i. Discounted Cash Flow Model

The DCF model is predicated on the concept that a stock's current price equals the present discounted value of the future dividends that investors expect to receive (Exhs. Unitil-SCH-1, at 19 (electric); Unitil-SCH-1, at 18 (gas)). Fitchburg's DCF analyses are based upon the following formula:

$$P_o = D_1 / (1 + k) + D_2 / (1 + k)^2 + ... + D_{¥} / (1 + k)^{¥}$$

where P_0 is today's stock price; D_1, D_2, etc. are all expected future dividends; and k is the discount rate (i.e., the investor's required ROE) (Exhs. Unitil-SCH-1, at 19 (electric); Unitil-SCH-1, at 18 (gas)).

The Company relied on three DCF models using the following method to forecast dividends for all future periods: (1) a constant growth (or Gordon) DCF model[232] using an average dividend growth rate of 5.33 percent; (2) a constant growth DCF model using a

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232 The constant growth DCF model is commonly expressed as:

$$k=D_1/P_0+g$$

where k is the investors' required return on common equity (or simply the cost of equity), D_1 is the dividend per share paid in the next period, P_0 is the current market price per share of the common stock, the term (D_1/P_0) is the expected dividend yield, and g is the investors' mean expected long-run growth rate in dividends per share (see Exhs. Unitil-SCH-1, at 19 (electric); Unitil-SCH-1, at 18 (gas)).

long-term gross domestic product ("GDP") growth rate of 5.8 percent; and (3) a two-stage DCF model[233] which is comprised of a non-constant growth rate for the first stage and a long-term GDP growth rate of 5.8 percent for the second stage (Exh. Sch. SCH-Rebuttal-4, at 2-4).

According to the Company, its constant growth DCF model using an average growth rate produces a range of ROEs between 9.8 percent and 9.9 percent and its constant growth DCF model using a GDP growth rate produces a range of ROEs between 10.3 percent and 10.5 percent (Exh. Sch. SCH-Rebuttal-4, at 1). Finally, Unitil states that its two-stage DCF model produces a range of ROEs between 10.1 percent and 10.2 percent (Exh. Sch. SCH-Rebuttal-4, at 1). Based on these results, the Company states that its revised analysis of the DCF models supports a range of ROEs between 9.8 percent and 10.5 percent (Exh. Unitil-SCH-Rebuttal-1, at 1).

233 To address the challenge in forecasting dividends for all future periods, the two-stage DCF model assumes that dividends for the first few periods grow at variable rates, while the dividends after that period grow at a long-term constant rate. The two-stage DCF model is expressed by the following equation:

$$P_0 = D_0(1 + g_1) / (1 + k) + . . . + D_2(1 + g_2)^n / (1 + k)^n + [D_T(1 + g_T)^{(T+1)} / (k - g_T)]/(1 + k)^T$$

where g_1 represents the growth rate for the first period, D_2 is the dividend at the beginning of the second period, and g_2 is the growth rate for the second period; and D_T is the dividend at the beginning of the third period, and g_T is the growth rate for or the period from year T (the end of the transition period) to infinity (Exhs. Unitil-SCH-1, at 21 (electric); Unitil-SCH-1, at 20-21 (gas)).

ii. Risk Premium Model

The risk premium model is based upon the theory that equity securities are riskier than debt and, therefore, that investors require a higher rate of return to invest in stocks rather than bonds (Exhs. Unitil-SCH-1, at 22 (electric); Unitil-SCH-1, at 21 (gas)).[234] The return that an investor requires above the cost of debt in exchange for investing in common stock is the equity risk premium.[235]

When applying the risk premium model, Fitchburg states that it prepared its analyses using projected and current interest rates in order to address the controversy as to whether it is best to use longer or shorter time periods of analysis (Exhs. Unitil-SCH-1, at 234 (electric); Unitil-SCH-1, at 22-23 (gas)). For its first calculation, Fitchburg used a projected triple-B utility bond yield of 6.38 percent as the starting point (Exhs. Sch. SCH-Rebuttal-5, at 1 (electric); Sch. SCH-Rebuttal-6, at 1 (gas)). To estimate its equity risk premium based on electric companies' returns, the Company first determined the difference between the averages of authorized electric company returns and public utility bond yields from 1980 through the third quarter of 2010 (i.e., 3.28 percent) (Exh. Sch. SCH-Rebuttal-5, at 1 (electric)). To

[234] Compared to bonds, stocks are considered riskier for several reasons including the fact that common stock holders are unsecured and behind bondholders in any claim on the corporation's assets and earnings (Exhs. Unitil-SCH-1, at 22-23 (electric); Sch. SCH-5 (electric); Unitil-SCH-1, at 21-22 (gas); Sch. SCH-5 (gas)). In addition, stock dividends can vary as compared to predictable bond coupon payments and stock prices can tend to be more volatile (Exhs. Unitil-SCH-1, at 22-23 (electric); Unitil-SCH-1, at 21-22 (gas)).

[235] For example, if the bond pays three percent and the stock return is eight percent, the equity risk premium is five percent.

estimate its equity risk premium based on gas companies' returns, the Company first determined the difference between the averages of authorized gas company returns and public utility bond yields from 1980 up to the third quarter of 2010 (i.e., 3.15 percent) (Exh. Sch. SCH-Rebuttal-6, at 1 (gas)). Based on what it states is an inverse relationship between interest rates and equity risk, the Company added an interest rate adjustment of 1.06 percent for electric and 1.07 percent for gas, producing adjusted total equity risk premia of 4.33 percent and 4.22 percent for electric and gas, respectively (Exhs. Sch. SCH-Rebuttal-5, at 1 (electric); Sch. SCH-Rebuttal-6, at 1 (gas)). Finally, Fitchburg calculated ROEs of 10.71 percent and 10.60 percent for its electric and gas operations respectively by adding the 6.38 percent projected bond yield to its 4.33 percent and 4.22 percent equity risk estimations (Exhs. Sch. SCH-Rebuttal-5, at 1 (electric); Sch. SCH-Rebuttal-6, at 1(gas)).

For the second calculation, Fitchburg used a current triple-B utility bond yield of 6.04 percent as the starting point (Exhs. Sch. SCH-Rebuttal-5, at 2 (electric); Sch. SCH-Rebuttal-6, at 2 (gas)). To estimate its equity risk based on electric companies' returns, the Company used the difference between the averages of authorized electric returns and average public utility bond yields from 1980 up to the third quarter of 2010 (i.e., 3.28 percent) (Exh. Sch. SCH-Rebuttal-5, at 2 (electric)). To estimate its equity risk based on gas companies' returns, the Company first determined the difference between the averages of authorized gas returns and public utility bond yields from 1980 up to the third quarter of 2010 (i.e., 3. 15 percent) (Exh. Sch. SCH-Rebuttal-6, at 1 (gas)). Based on the inverse relationship between interest rates and equity risk, the Company added an interest rate adjustment of 1.20 percent for electric and 1.21 percent for gas to arrive at total equity risk premia of 4.47 percent for electric and 4.36 percent for gas (Exhs. Sch. SCH-Rebuttal-5, at 2 (electric); Sch. SCH-Rebuttal-6, at 2 (gas)). Finally, Fitchburg calculated ROEs of 10.51 percent and 10.40 percent for its electric and gas divisions, respectively by adding the 6.04 percent current bond yield to its 4.47 percent and 4.36 percent equity risk estimations (Exhs. Sch. SCH-Rebuttal-5, at 2 (electric); Sch. SCH-Rebuttal-6, at 2 (gas)).

c. Recommendation

As noted above, the results of Fitchburg's DCF analyses produce a range of ROEs of between 9.8 percent and 10.5 percent, and its risk premium analyses produce a range of ROEs of between 10.4 percent and 10.7 percent (Exh. Unitil-SCH Rebuttal-1, at 26). The Company placed little weight on the results of its risk premium analyses because of what it considers to be artificially low interest rates being driven by the federal government's current expansionary monetary policy which it states is likely to understate ROE over the long-term (Exhs. Unitil-SCH-1, at 40-41 (electric); Unitil-SCH-1, at 43 (gas)). In view of Fitchburg's smaller size and lower common equity ratio versus the companies in its proxy group and the continuing "turmoil" in the capital markets that Fitchburg states may not be captured by traditional DCF theory, the Company selected the upper end of the range of its DCF analyses (i.e., 10.5 percent) as a reasonable measure of its required ROE (Exhs. Unitil-SCH-1, at 41 (electric); Unitil-SCH-1, at 43 (gas); Unitil-SCH-Rebuttal-1, at 26).

The Company states that its proposed ROE already takes into account the material effect that implementation of its proposed decoupling mechanism will have on its risk profile and, therefore, made no further adjustment in this regard (Exhs. Unitil-SCH-1, at 7-10 (electric); Unitil-SCH-1, at 6-9 (gas)). Further, the Company states that no adjustments to its ROE are appropriate to account for its management performance related to Winter Storm 2008 or otherwise (Exh. Unitil-SCH-1, at 6-7 (electric)).

2. Attorney General's Proposal

a. Introduction

Unlike the Company's proposal of a single ROE for both divisions, the Attorney General proposes separate ROEs for Fitchburg's electric and gas divisions based on the results of two equity cost models: the DCF model and the capital asset pricing model ("CAPM") (Exh. AG-JRW-1, at 2). For the electric division, the Attorney General initially recommended an ROE of 9.25 percent (Exh. AG-JRW-1, at 2, 47-48). For the gas division, the Attorney General initially recommended an ROE of 8.75 percent (Exh. AG-JRW-1, at 2, 47-48). However, on brief, the Attorney General reduced her recommended ROE for the electric division from 9.25 percent to 8.75 percent and reduced her recommended ROE for the gas division from 8.75 percent to 8.50 percent to account for what she contends are significant deficiencies in the Company's management performance (Attorney General Brief at 170-172).

b. Financial Models

i. Discounted Cash Flow Model

The Attorney General applied the constant growth DCF model using an average dividend growth rate (Exhs. AG-JRW-1, at 23-24). In applying the DCF model, the Attorney General determined the dividend yields on the common stock of the companies in her electric and gas proxy groups, using a median six-month dividend yield of 4.7 percent and 3.9 percent for the electric and gas divisions, respectively (Exh. AG-JRW-10, at 2). The Attorney General then averaged these figures with the April 2011 median dividend yields for her electric and gas proxy groups of 4.8 percent and 3.9 percent, respectively, resulting in an unadjusted dividend yield of 4.75 percent for the electric proxy group and 3.90 percent for the gas proxy group (Exhs. AG-JRW-1, at 26; AG-JRW-10, at 1-2). The Attorney General adjusted this dividend yield by one-half of the expected growth rate (a factor of 1.0225 for the electric proxy group and a factor of 1.0205 for the gas proxy group)[236] to recognize growth in the coming year (Exhs. AG-JRW-1, at 26-27; AG-JRW-10, at 1). For her electric proxy group, this calculation results in a 4.9 percent[237] adjusted dividend yield (Exh. AG-JRW-10, at 1). For her gas proxy group, this calculation results in a 4.0 percent[238] adjusted dividend yield (Exh. AG-JRW-10, at 1).

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[236] This factor is calculated by multiplying the 4.30 percent growth rate by one-half and adding one to it, resulting in 1.0215 (Exh. AG-JRW-10, at 1).

[237] This figure is rounded up from 4.8568 (4.75 x 1.0225) (Exh. AG-JRW-10, at 1).

[238] This figure is rounded up from 3.9799 (3.90 x 1.0205) (Exh. AG-JRW-10, at 1).

In order to arrive at the growth rate that she uses in her electric DCF model analysis, the Attorney General calculated the average of projected and sustainable growth rate indicators for the electric proxy group as 4.5 percent (Exhs. AG-JRW-1, at 32-35; AG-JRW-10, at 3-6). Combining an adjusted dividend yield of 4.9 percent with a growth rate of 4.5 percent, the Attorney General’s DCF model analysis produces an ROE of 9.4 percent for the Company’s electric division (Exhs. AG-JRW-1, at 35; AG-JRW-10, at 1).

Similarly, in order to arrive at the growth rate that she uses in her gas DCF model analysis, the Attorney General calculated the average of the projected and sustainable growth rates indicators for the gas proxy group as 4.1 percent (Exhs. AG-JRW-1, at 32-35; AG-JRW-10, at 4-6). Combining an adjusted dividend yield of 4.0 percent with a growth rate of 4.1 percent, the Attorney General’s DCF model analysis produces an ROE of 8.1 percent for the gas division (Exhs. AG-JRW-1, at 35; AG-JRW-10, at 1).

ii. Capital Asset Pricing Model

Under the CAPM, the expected return of an equity security is equal to: (1) the rate on a risk-free security to compensate investors for placing money in any investment over a period of time (i.e., the time value of money); plus (2) an additional premium to compensate equity investors for taking on two forms of risk from the investment: (a) market-specific risk, otherwise known as systematic risk, and (b) firm-specific risk, otherwise known as unsystematic risk (Exhs. AG-JRW-1, at 36). The Attorney General's CAPM analyses are based on the following formula where the expected return on a company's stock or equity cost rate (K), is equal to:

$$K = R_f + ß * [E(R_m) - (R_f)]$$

where: (1) R_f is the risk free rate; (2) ß (or beta) is the measure of individual stock risk relative to the market risk; and (3) $E(R_m)$-(R_f) is the equity risk premium, or the difference in the expected returns between investing in equity securities and investing in safer, fixed-income securities (Exh. AG-JRW-1, at 36-40).

The Attorney General used the 30-year Treasury bond rate as a proxy for the risk-free rate (Exh. AG-JRW-1, at 38). She maintains that the yield on 30-year Treasury bonds has been in the 4.0 percent to 4.75 percent range over the last six months and that the rate was 4.50 percent as of March 28, 2011 (Exh. AG-JRW-1, at 38). The Attorney General employed Value Line betas, calculating a median beta of 0.70 for the electric division and 0.65 for the gas division (Exhs. AG-JRW-1, at 39; AG-JRW-11, at 3).

To develop her equity risk premium, the Attorney General compiled a comprehensive list of studies of historical risk premiums, "ex-ante" models, assorted academic and business surveys, and a building block method[239] from which she extracted a subset of studies published after January 2, 2010 (Exhs. AG-JRW-1, at 42-46; AG-JRW-11, at 5-6). The Attorney General used the median equity risk premium of 4.95 percent from the results of this subset of studies (Exhs. AG-JRW-1, at 44; AG-JRW-11, at 6).

239 According to the Attorney General, the building blocks method is a hybrid approach employing elements of both the historic and "ex ante" approaches (Exh. AG-JRW-1, at 43).

Using a risk free rate of 4.50 percent, a beta of 0.70, and a median equity risk premium of 4.95 percent, the Attorney General calculated an ROE of 8.0 percent for the electric division using the CAPM (Exhs. AG-JRW-1, at 47; AG-JRW-11, at 1). Likewise, using a risk free rate of 4.50 percent, a beta of 0.65, and a median equity risk premium of 4.95 percent, the Attorney General calculated an ROE of 7.7 percent for the gas division (Exhs. AG-JRW-1, at 47; AG-JRW-11, at 1).

c. Recommendation

For the electric division, the results of the Attorney General's DCF model analysis produces an ROE of 9.4 percent, and her CAPM analysis produces an ROE of 8.0 percent (Exhs. AG-JRW-1, at 47; AG-JRW-10, at 1; AG-JRW-11, at 1). For the gas division, the results of the Attorney General's DCF model analysis produces an ROE of 8.1 percent, and her CAPM analysis produces an ROE of 7.7 percent (Exhs. AG-JRW-1, at 47; AG-JRW-10, at 1; AG-JRW-11, at 1).

Because she places more weight on the DCF model and considers her gas proxy group to be less risky than her electric proxy group, the Attorney General's recommended cost of equity is based on a range of ROEs from 8.5 percent to 9.4 percent for the electric division and 8.0 percent to 8.5 percent for the gas division. The midpoints of these ranges are 9.0 percent and 8.25 for the electric and gas divisions, respectively (Exhs. AG-JRW-1, at 47-48). To account for the financial risk differential between the electric proxy group's equity ratio and Fitchburg's equity ratio, the Attorney General adds 25 basis points to the midpoint of the electric range (i.e., 9.0 percent) to arrive at an ROE of 9.25 percent for the electric division (Exh. AG-JRW-1, at 48). Similarly, to account for the financial risk differential between the gas proxy group's equity ratio and Fitchburg's common equity ratio, the Attorney General adds 50 basis points to the midpoint of the gas range (i.e., 8.25 percent) to arrive at an ROE of 8.75 percent for the gas division (Exh. AG-JRW-1, at 48).[240]

Although she believes such adjustment is warranted, the Attorney General makes no specific recommendation on an ROE adjustment based on the reductions in risk associated with the Company's rate design proposal in this proceeding (Exhs. AG-JRW- 1, at 49). However, the Attorney General reduced her recommended ROE to 8.75 percent for the electric division and 8.50 percent for the gas division to account for what she contends are deficiencies in the Company's management performance (Attorney General Brief at 170-171).

3. Positions of the Parties

a. Introduction

i. Attorney General

The Attorney General reduced her recommended ROE for the electric division from 9.25 percent to 8.75 percent and reduced her recommended ROE for the gas division from 8.75 percent to 8.50 percent (Attorney General Brief at 170-171). In support of her revised recommendation, the Attorney General states that her initial recommendation was for a utility

[240] The Attorney General explains that these risk differentials are due to her use of an electric proxy group with a common equity ratio of 46.4 percent and a gas proxy group with a common equity ratio of 49.4 percent, as opposed to the Company's lower common equity ratio of 42.9 percent (Exhs. AG-JRW-1, at 48 (electric); AG-JRW-1, at 48 (gas)).

that is economically and efficiently managed (Attorney General Brief at 170-171). However, as discussed below, the Attorney General states that Department precedent requires that Fitchburg's ROE be set at the lower end of the Attorney General's recommended range because of deficiencies in the Company's management performance (Attorney General Brief at 171, citing D.P.U. 09-01-A at 198; Attorney General Reply Brief at 43-44).

To arrive at her revised ROE of 8.75 percent for the electric division, the Attorney General states that she began at the low end of the range recommended by her electric model analysis (i.e., 8.50 percent) to account for poor management performance, and then added 25 basis points to account for Fitchburg's lower common equity as compared to that of her electric proxy group (Attorney General Brief at 171).

Similarly, to arrive at her revised ROE of 8.50 percent for the gas division, the Attorney General states that she began at the low end of the range recommended by her gas model analysis (i.e., 8.0 percent) to account for poor management performance, and then added 50 basis points to account for Fitchburg's lower common equity ratio as compared to that of her gas proxy group (Attorney General Brief at 171-172). To support the reasonableness of her recommended gas ROE, the Attorney General alleges that a June 2, 2011, draft decision by the Connecticut Department of Public Utility Control ("CPUC") provides for an ROE of 8.83 percent in Yankee Gas Services' pending rate proceeding even when evidence of imprudence was absent in that proceeding (Attorney General Reply Brief at 44, citing CPUC Docket No. 10-12-02).

ii. Fitchburg

The Company argues that its proposed ROE is appropriately based on a group of companies that have corresponding risks, including various decoupling mechanisms. Specifically, Fitchburg argues that its proposed ROE is commensurate with returns on investments in similar enterprises having corresponding risks (Company Brief at 100, citing Attorney Gen. v. Department of Public Utilities, 392 Mass. 262, 266 (1982)).

Fitchburg argues that, in order for the Attorney General to support her recommended ROEs of 8.75 percent for the electric division and 8.50 percent for the gas division, she has to reject her expert's initial recommendation of an ROE of 9.25 for Fitchburg's electric division and 8.75 percent for Fitchburg's gas division, which the Company notes are still too low to sustain its utility operations or to attract capital at a reasonable cost (Company Brief at 98). According to the Company, the Attorney General's expert testified that natural gas and electric utilities earned ROEs of between 10.1 percent and 10.9 percent in 2010 (Company Brief at 98, citing Exh. AG-JRW-1, at 17-18). Fitchburg argues that the Attorney General's witness was unable to cite an instance where a regulated utility received an ROE of 8.75 percent or less (Company Brief at 99, citing Tr. 14, at 1770).

The Company argues that an ROE of 9.0 percent or below would put the Company at a severe disadvantage as compared to other electric and gas companies in terms of attracting capital (Company Brief at 98; Company Reply Brief at 48). The Company notes that at least one state utility commission has rejected an ROE of 9.0 percent for an electric utility as "outside the zone of reasonableness" (Company Brief at 99-100, citing Exh. Unitil-SCH-Rebuttal-1, at 3, citing Missouri Public Service Commission, Final Order, Kansas City Power and Light Company, Case No. ER-2006-0314, December 21, 2006, at 22-23; Company Reply Brief at 46).

b. Single vs. Separate Returns on Equity

i. Attorney General

According to the Attorney General, her comparison of the electric proxy group and the gas proxy group demonstrates that the gas proxy group is less risky on all financial metrics that she considered (Attorney General Brief at 159, citing Exh. AG-JRW-4, at 2). Therefore, the Attorney General argues that the Department should set separate ROEs for the Company's electric and gas divisions to reflect the gas division's lower risk (Attorney General Brief at 159).

ii. Fitchburg

Fitchburg argues that the Department should apply a single ROE for both of the Company's operating divisions (Company Brief at 93). The Company asserts that the Attorney General's gas proxy group is too small to produce statistically reliable results concerning the risk of its gas division relative to its electric division (Company Brief at 92, citing D.P.U. 10-55, at 511). Further, the Company maintains that numerous studies demonstrate that there is no significant difference between the ROEs granted to gas companies versus those granted to electric companies (Company Brief at 93, citing Tr. 12, at 1527-1528). Therefore, the Company maintains that using a proxy group consisting of a large number of electric companies for the purposes of setting the Company's ROE is appropriate (Company Brief at 93).

c. Financial Models

i. Discounted Cash Flow Model

(A) Attorney General

The Attorney General submits that her major areas of disagreement with Fitchburg's application of the DCF model are the Company's assumptions regarding the expected growth rate (Attorney General Brief at 157). The Attorney General argues that the long-term earnings growth rates cited by Fitchburg are overly optimistic and upwardly biased (Attorney General Brief at 160, citing Exhs. AG-JRW-1, at 31-32, 53-62; AG-JRW-Rebuttal-1, at 6; Attorney General Reply Brief at 40). Further, the Attorney General contends that the Company's estimated long-term earnings per share growth rates are also overstated (Attorney General Brief at 160; Exh. AG-JRW-Rebuttal-1, at 6). The Attorney General submits that she corrected for these biases when she used both historic and projected growth rate measures in her DCF analyses (Attorney General Brief at 160).

Further, the Attorney General criticizes Fitchburg's GDP growth estimate of 5.8 percent because she contends it is inconsistent with both historic trends and current forecasts of GDP (Attorney General Reply Brief at 40, citing Exhs. AG-JRW-1, at 162-164; AG-JRW-Rebuttal-1, at 8, 10). The Attorney General argues that GDP growth rates over the past ten to 20 years have been 3.9 and 4.8 percent, respectively, suggesting that a GDP growth rate of 5.0 percent is more appropriate (Exh. AG-JRW-Rebuttal-1, at 9-10, citing Sch. SCH-Rebuttal-3).

Finally, regarding the dividend yield, the Attorney General asserts that it was not appropriate for the Company to make to make a full-year growth adjustment to the dividend yield because companies change their quarterly dividend payments at different times during the year (Attorney General Brief at 162).

(B) Fitchburg

The Company argues that its application of the DCF model was appropriate (Company Brief at 96). First, Fitchburg argues that its reliance on forecast data was correct because (1) individual investors rely on analysts' forecasts in making investment decisions as analysts' forecasts provide greater insight into prospective growth than historical measures, and (2) earnings per share forecasts are the principal driver of stock prices (Company Brief at 94, citing Tr. 6, at 534-535). The Company claims that the Department has recognized the value of forecast data as a conceptually appropriate measure of growth (Company Reply Brief at 45, citing D.T.E. 05-27, at 298; D.T.E. 03-40, at 358). In addition, Fitchburg claims that the Attorney General has recognized that one must use historical growth numbers as measures of investors' expectations with caution (Company Brief at 94, citing Exh. AG-JRW-1, at 28, Tr. 14, at 1765-1766).

Second, the Company argues that the growth rate projections used in its DCF models were appropriate (Company Brief at 94). The Company contends that there is little upward bias in earnings per share growth rate projections for gas distribution companies; the difference between actual and projected earnings per share growth rates for gas distribution companies was only 62 basis points over the last three to five years (Company Brief at 94, citing Exh. AG-JRW-1, at 63). Further, the Company argues that the recent difference between actual and projected earnings per share growth rates for electric distribution companies is the result of the "trading disasters and restructuring" that occurred in 2004 and 2005 which led to unexpected negative growth rates for electric utilities not anticipated by analysts (Company Brief at 94, citing Exh. Unitil-SCH-Rebuttal- 1, at 20-21; Company Reply Brief at 45). The Company argues that, other than the limited studies performed by the Attorney General's own witness, there are no studies or research showing any upward bias in analysts' forecasts for electric and gas companies (Company Brief at 94-95, citing Exh. Unitil-SCH-Rebuttal-1, at 20; Tr. 14, at 1766).

Third, Fitchburg argues that its updated long-term GDP growth rate forecast of 5.8 percent is not overstated (Company Brief at 96, citing Exh. Unitil-SCH-Rebuttal-1, at 23). Fitchburg claims that it is a mature firm (like all other utilities) and, therefore, it can be expected to increase its dividends at the same rate as GDP (Company Brief at 95, citing Exh. Unitil-SCH-Rebuttal-1, at 22; Tr. 14, at 1767). Fitchburg notes that the Attorney General's own projected GDP growth rate of 5.6 percent is close to its own projection when inflation is taken into account (Company Brief at 96, citing Exh. Unitil-SCH-Rebuttal-1, at 22). Fitchburg maintains that its proposed growth rate accounts for GDP growth is supported by analysts' forecasts, and is consistent with published research (Company Brief at 96, citing Exh. Unitil-SCH-Rebuttal-1, at 23).

ii. Risk Premium Model

(A) Attorney General

With respect to the Company's use of the risk premium model, the Attorney General argues that the Company's base interest rates are inflated because the yield on long-term bonds overstates the required ROE (Attorney General Brief at 167-168). Further, the Attorney General criticizes the Company's measurement of the risk premium (Attorney General Reply Brief at 42). Specifically, the Attorney General argues that Fitchburg's approach is circular in that electric utilities' authorized ROEs are used to derive the Company's risk premium in this proceeding (Attorney General Brief at 168; Attorney General Reply Brief at 42, citing Exh. AG-JRW-1, at 69). However, the Attorney General posits that these historic allowed ROEs are above equity cost rates (Attorney General Reply Brief at 42, citing Exh. AG-JRW-1, at 69).

(B) Fitchburg

The Company maintains that its application of the risk premium model is consistent with widely accepted and fundamental capital market principles (Company Brief at 88, citing Exhs. Unitil-SCH- 1, at 2 (electric); Unitil-SCH- 1, at 21 (gas)). Specifically, the Company contends that it appropriately compared historic allowed ROEs to contemporaneous long-term bond rates, and then applied that equity risk premium to appropriate long-term bond rates (Company Brief at 89, citing Schs. SCH Rebuttal-5, at 1-2; Sch. SCH Rebuttal-6, at 1-2).

Fitchburg also argues that it appropriately considered the results of the risk premium model when it recommended an ROE of 10.5 percent (Company Brief at 89, citing Exhs. Unitil-SCH- 1, at 41 (electric); Unitil-SCH- 1, at 40-41 gas); Unitil-SCH-Rebuttal-1, at 1).

iii. Capital Asset Pricing Model

(A) Attorney General

The Attorney General argues that the primary difficulty when conducting a CAPM analysis is the measurement of the equity risk premium (Attorney General Brief at 165). However, the Attorney General contends that her equity risk premium of 4.95 percent is consistent with several recent studies including: (1) equity risk premia in the 3.5 percent to 4.0 percent range used by a leading management consulting firm for corporate valuation purposes; (2) an equity risk premium of 5.0 percent contained in a 2010 survey of financial analysts and companies; (3) the ex ante equity risk premium of 3.7 percent contained in a March 2011 survey of chief financial officers; and (4) the ex ante equity risk premium of 2.87 percent contained in the Federal Reserve Bank of Philadelphia’s annual Survey of Professional Forecasters published on February 11, 2011 (Attorney General Brief at 166-167, citing Exh. AG-JRW-1, at 43-44).

(B) Fitchburg

The Company argues that the Attorney General’s CAPM approach is flawed because it is based on an unrealistic equity risk premium (Company Brief at 96-97, citing Exh. Unitil-SCH-Rebuttal-1, at 2). Further, Fitchburg argues that, under current market conditions, the artificially low risk-free government interest rates caused by monetary stimulus programs cause the CAPM to understate ROE (Company Brief at 97, citing Exh. Unitil-SCH-Rebuttal-1, at 17). Finally, Fitchburg argues that the results of the Attorney General's CAPM are too low because triple-B utility bond yields are currently above 6.0 percent and current forecasts indicate that interest rates are going to rise (Company Brief at 97, citing Tr. 6, at 601).

d. Impact of Decoupling on Cost of Equity

i. Attorney General

The Attorney General submits that a reduction in earnings volatility should reduce risks to shareholders and, thereby, lower the required ROE (Attorney General Brief at 155, citing D.P.U. 07-50-A, at 72-73). The Attorney General argues that if the Department approves an electric revenue decoupling mechanism for Fitchburg, then the Company's ROE must recognize the lower risk to its electric operations as a result (Attorney General Brief at 155). On the gas side, the Attorney General argues that the Company has already hedged a significant portion of its business risk with fully-reconciling rate mechanisms for gas costs, environmental clean-up, pensions, and other costs and, therefore, that the Company's gas ROE should reflect this lower risk (Attorney General Brief at 155). Further, the Attorney General argues that if the Department approves a gas revenue decoupling mechanism for Fitchburg, then the Company's ROE must also recognize the lower risk to its gas operations as a result (Attorney General Brief at 155).

ii. Fitchburg

Fitchburg argues that the Department must determine ROE based on an assessment of comparative investment opportunities in the market place (Company Brief at 89, citing Attorney General v. Department of Public Utilities, 392 Mass. 262, 266 (1984) quoting Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("Hope")). According to the Company, in determining whether the implementation of revenue decoupling should have an impact on its authorized ROE, it is relevant to compare investors' perceptions of the risk profile of a decoupled Fitchburg to the risk profile of its proxy group (Company Brief at 89). To this end, Fitchburg argues that the companies in its proxy group have operations that are comparable to the Company and, specifically, that approximately half of the companies in its proxy group have revenue stabilization mechanisms in place such as decoupling (Company Brief at 89, citing Exhs. Sch. SCH-1, at 9 (electric); Sch. SCH-1, at 8 (gas)).

For this reason, the Company disputes the Attorney General's argument that the Department should reduce the Company's ROE due to the implementation of decoupling and other fully reconciling rate mechanisms (Company Brief at 97). Fitchburg argues that investors are aware that companies in the proxy group have revenue stabilization mechanisms of one form or another and have accounted for the impact of those mechanisms in pricing their stocks (Company Brief at 90). Fitchburg opines that, if the Department were to make a further downward adjustment for the implementation of revenue decoupling as suggested by the Attorney General, it would double-count the impact (Company Brief at 90).

e. Adjustments for Management Performance

i. Attorney General

The Attorney General notes that the Department has a long-standing practice of considering the regulatory service and regulatory records of gas and electric companies in setting required ROEs (Attorney General Brief at 155-156, citing D.P.U. 10-114, at 340). The Attorney General asserts that the Company's allowed ROE must reflect not only the record in this case, but also the record in the Winter Storm 2008 investigation as well as the Department's prior Orders concerning Fitchburg (Attorney General Brief at 155, citing D.P.U. 09-01-A). The Attorney General argues that Fitchburg's sub-par performance must have consequences that "go beyond stern admonitions to do better" (Attorney General Brief at 155). Therefore, the Attorney General argues that, when setting the Company's allowed ROE, the Department must consider the significant deficiencies in the Company's management performance over the last twelve years (Attorney General Brief at 170-171).

ii. Fitchburg

Fitchburg argues that the Department should not make any reduction to the Company's ROE as a result of its response to Winter Storm 2008 (Company Brief at 90; Company Reply Brief at 47-48). Fitchburg asserts that Winter Storm 2008 was a unique and major storm event and that the Department itself has concluded that the Company's service quality has met the Department's service quality guidelines (Company Brief at 91). Accordingly, the Company contends that a reduction in its ROE related to the Company's response to a single large storm would not be justified (Company Brief at 91). Further, Fitchburg argues that a reduction in its ROE would increase the Company's cost of capital, making it difficult for the Company to respond to future unexpected events (Company Brief at 91; Company Reply Brief at 48).

4. Analysis and Findings

a. Introduction

As support for its recommended ROE of 10.5 percent, Fitchburg applied the DCF model and the risk premium model using the financial data of 30 electric and gas utility companies that constitute its proxy group (Exh. Unitil-SCH-Rebuttal-1, at 26). Likewise, to arrive at her recommended ROE of 8.75 percent for the electric division and 8.5 percent for the gas division, the Attorney General applied the DCF model and the CAPM using the financial data of 29 electric companies in her electric proxy group and eight gas companies in her gas proxy group (Exhs. AG-JRW-1, at 10-11; AG-JRW-4, at 1-2).

Approximately half of the companies in Fitchburg's proxy group employ some form of revenue stabilization or revenue decoupling mechanism for at least some element of their regulated businesses (Exhs. Unitil-SCH- 1, at 9 (electric); Unitil-SCH- 1, at 8 (gas)). The Attorney General did not use a revenue stabilization mechanism as a criterion for selection of her comparison group (Exh. AG-JRW at 10-11).[241] Rather, the companies in her electric comparison group: (1) receive on average 81 percent of their revenues from regulated electric operations; (2) have an A-/BBB+ bond rating from S&P; and (3) have current median equity

[241] Nonetheless, certain of the companies in the Attorney General's gas and electric proxy groups have implemented some form of revenue decoupling (see Exhs. AG-6-1, Att. B at 26, 55, 99, 141, 148, 249 (gas); AG-7-1, Att. B at 26, 55, 99, 141, 148, 249 (electric)).

ratio of 46.4 percent (Exhs. AG-JRW- 1, at 11; AG-JRW-4, at 1). Similarly, the Attorney General's gas proxy group include companies that must: (1) be listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports; (2) be listed as a natural gas utility in the Standard Edition of Value Line; (3) receive at least 50 percent of revenues from regulated gas operations; (4) have an investment grade bond rating by Moody's and S&P; and (5) have a current median equity ratio of 49.2 percent (Exhs. AG-JRW-1, at 10-11; AG-JRW-4, at 1).

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 Fitchburg 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 Fitchburg's as well as the Attorney General's comparison groups of electric and gas utility companies with publicly traded stocks as a basis to evaluate their cost of capital proposals, but will consider the investment risk of Fitchburg versus the comparison groups when determining the appropriate ROE for the Company.

b. Single vs. Separate Returns on Equity

As noted above, the Company proposes a single ROE of 10.5 percent for its electric and gas divisions (Exh. Unitil-SCH-Rebuttal- 1, at 1). According to the Company, its proxy group consisting of a large number of electric companies and a smaller number of gas companies is appropriate for setting the ROE for a gas distribution company, given what it contends is an insignificant difference between the risk profiles of gas and electric companies (Company Brief at 93, citing Tr. 12, at 1528). On the other hand, the Attorney General proposes to apply separate ROEs for the Company's gas and electric divisions of 8.50 percent and 8.75 percent, respectively (Exh. AG-JRW-1, at 2). The Attorney General's maintains that her analysis demonstrates that her gas proxy group is less risky than her electric proxy group based on all five financial metrics she considered (Attorney General Brief at 159, citing Exh. AG-JRW -4, at 2). Therefore, the Attorney General argues that the Department should set separate ROEs for the Company's gas and electric operating divisions to reflect the gas division's lower equity cost rate (Attorney General Brief at 159).

The standard for determining a company's capital structure is set forth in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia v. Public Service Commission of West Virginia, 262 U.S. 679 at 692-293 (1923) ("Bluefield") and Hope at 603. Specifically, the allowed ROE should preserve a company's financial integrity, allow a company to attract capital on reasonable terms, and be comparable to returns on investments of comparable risk. Bluefield at 692-293; Hope at 603. Therefore, the evaluation of a company's financial risk is a significant factor in determining an appropriate ROE.

Typically gas utilities have been considered to be less risky than electric utilities. However, the Department notes that, with the elimination of electric generation-related risks resulting from electric restructuring, the risk differential between electric and gas utilities has moderated. In cases where combined utilities are seeking rate changes pursuant to G.L. c. 164, § 94, the Department has the discretion to authorize a single ROE or separate

ROEs. See Attorney General v. Dep't of Public Utilities, 392 Mass. at 268-269 (given subjective nature of ROE calculations, court determined the Department was well within its discretion to apply a "Company-wide" cost of equity).

It is not unusual for Fitchburg to file gas and electric rate cases at different times and, as a result, Fitchburg has operated with separate allowed ROEs for its gas and electric divisions. See e.g., D.T.E. 07-71, at 139; D.T.E. 98-51, at 127. However, adopting one ROE for Fitchburg's combined operations is consistent with the Department's historic practice when simultaneous gas and electric rate filings have been made. D.T.E. 02-24/25; Fitchburg Gas and Electric Light Company, D.P.U. 19084 (1977); Fitchburg Gas and Electric Light Company, D.P.U. 18296/18297 (1975). Moreover, the practice of setting one ROE is consistent with the Department's treatment of other combined utilities where the company has proposed simultaneous changes to both its gas and electric rates pursuant to G.L. c. 164, § 94. See e.g., New Bedford Gas and Edison Light Company, D.P.U. 18193/18193-A (1975); New Bedford Gas and Edison Light Company, D.P.U. 16317 (1970). In setting a single ROE for a company's gas and electric divisions, the Department has recognized that the company's operating divisions are part of a single corporate structure that dispenses consolidated financial information, including combined statements of earnings, retained earnings, cash flow, and long-term debt. See Fitchburg Gas and Electric Light Company, D.P.U. 1214, at 57-58 (1983). As the Department found in D.P.U. 1214, at 58, setting a single ROE for a company's operating divisions recognizes the fact that investors make decisions based on the overall risk of the company.

The record in these cases show that the Company's operating divisions are subsumed under a single corporate structure that dispenses consolidated financial information, including combined statements of earnings, retained earnings, cash flow, and long-term debt (Exhs. AG-1-2, Att. 3G; at 9-23 (electric); AG-1-2, Att. 1-2 (gas)). The results of the Attorney General's cost of capital models tend to show that Fitchburg's gas operations are somewhat less risky than its electric operations, and we find such analysis useful in this case (Exhs. AG-JRW-10; AG-JRW-11). However, as we discussed in above, while the Attorney General used reasonable selection criteria, the number of companies in the Attorney General's gas proxy group is small, and this affects the weight we give to such results. See D.P.U. 10-55, at 481; Massachusetts-American Water Company, D.P.U. 1700, at 28 (1984); Oxford Water Company, D.P.U. 1699, at 26 (1984).

In this instance, we are not persuaded that the risk differential between Fitchburg's gas and electric divisions is significant enough to warrant a departure from our historic treatment of applying a single ROE to the Company's operations. We find that setting a single ROE for the Company's gas and electric operating divisions appropriately recognizes the fact that investors make decisions based on the overall risk of the Company. Accordingly, we will adopt a single ROE for the Company's electric and gas divisions.

c. Financial Models

i. Discounted Cash Flow Model

Both the Company and the Attorney General use a form of the DCF model which assumes an infinite investment horizon and a constant growth rate (Exhs. Unitil-SCH-1, at 19 (electric); Unitil-SCH-1, at 18 (gas); AG-JRW-1, at 24). This model has a number of very strict assumptions (e.g., it assumes an infinite investment horizon and that dividends grow at a constant rate in perpetuity) (Exhs. Unitil-SCH- 1, at 19 (electric); Unitil-SCH- 1, at 18 (gas); AG-JRW- 1, at 24). These assumptions affect the calculation of ROE.

Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358. In addition, the DCF model includes an element of circularity when applied in a rate case, because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 258; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the reliability of both the Company's constant growth and two-stage DCF models. While the Attorney General's DCF model attempts to compensate for this circularity by placing less emphasis on analyst forecasts of earnings per share growth rates, an element of circularity remains in her DCF model as well (Exh. AG-JRW-1, at 31-32).

The Company used a variant of the DCF model using long-term GDP growth as the growth rate (Exhs. Sch. SCH-4, at 3 (Electric); Sch. SCH-4, at 4 (gas)). The evidence of long-term GDP growth rates presented here, however, indicates that the Company's selection of long-term GDP growth rates for both its constant growth and two-stage DCF models overstates the required ROE (Exh. AG-JRW-Rebuttal-1, at 9-10; Sch. SCH-Rebuttal-3). Moreover, while utilities may fairly be considered mature firms, the Department is not persuaded that this concept necessarily translates into an ability to equate the actual dividend policies of regulated utilities (much less those of individual companies) with GDP growth. Consequently, we find that the GDP growth rate may overstate the results of both the Company's constant growth and two-stage DCF models.

The Department recognizes the limitations of the DCF model, particularly in the determination of the growth component. D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358; D.P.U. 08-35, at 199. Accordingly, we will consider these model limitations in evaluating the ROEs based on the DCF model that are presented in this proceeding when determining the Company's allowed ROE.

ii. 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. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, that the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a supplemental approach to other ROE models. D.P.U. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In this particular case, the Company’s risk premium model suffers from a number of limitations, including potential imprecision in the assessment of future cost of corporate debt and the measurement of the risk-adjusted common equity premium. The Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Department has also recognized the circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183.

For these reasons, the Department finds that Fitchburg’s risk premium model tends to overstate the required ROE for the Company. Accordingly, we will place limited weight on the results of the Company’s risk premium model.

iii. Capital Asset Pricing Model

The Department has previously found that the traditional CAPM as a basis for determining a utility’s cost of equity has limited value and, in some cases no value, because of a number of limitations including questionable assumptions that underlie the model. D.P.U. 10-114, at 318; D.P.U. 10-70, at 267; D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54.[242] For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk-free rate, and has found that coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67, Phase I at 184.

The Attorney General's CAPM analysis relies on 30-year Treasury bond rates as a proxy for the risk-free rate (Exh. AG-JRW- 1, at 38). Current federal monetary policy intended to stimulate the economy, such as bond buyback programs, have pushed treasury yields to near-historic lows (Exh. Unitil-SCH-Rebuttal-1, at 17; Tr. 7, at 603). Consequently, a CAPM analysis based on current treasury yields at historic lows may tend to underestimate the risk-free rate over the long term, and thereby understate the required ROE. Based on the above considerations, the Department will place limited weight on the results of the Attorney General's CAPM.

[242] The Department has 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. D.P.U. 08-35, at 207 n.131.

d. Impact of Decoupling on Cost of Equity

In D.P.U. 07-50-A at 72, 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. See also 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. Accordingly, in these cases, we must consider the impact of the Company's revenue decoupling mechanisms on its allowed ROE.

The evidence in these proceedings demonstrates that the variability in the Company's base distribution revenues will be significantly reduced as a result of the design of the revenue decoupling mechanisms approved in these cases (see Section VI, above). The annual revenue requirements approved by the Department are established on the basis of the distribution revenue requirement approved in this case and test year billing determinants (see Section VI, above). Further, the approved revenue requirements include a provision for the Company's return on capital (see Schedule 1 of this Order). Prior to revenue decoupling, any variations in billing units from test year levels arising from factors such as changes in the weather were reflected in the level of distribution revenues actually collected by the Company. Similarly, any changes in economic factors, such as the impact of price increases, affected the amount of distribution revenues actually collected by the Company.

Under the revenue decoupling mechanisms approved in this proceeding, the Company at the end of each annual period[243] will compare the difference between its target revenues for its electric and gas divisions with the actual billed base distribution revenues and refund or collect the difference through an RDM adjustment reconciliation (see Section VI, above). Because the Company will recover fully during the ensuing years its approved base distribution revenue requirement, we find that the RDM adjustment will result in rate year distribution revenues that will be sufficient to meet the distribution revenue requirement approved in this base rate proceeding.

For gas companies, the Department has previously rejected proposals for adjusting rate year revenues between rate filings due to variations 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 a weather adjustment would result in a less risky profile for a company, 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 cases, changes in sales arising from almost all factors, including weather and reduced energy consumption, will be decoupled from the Company's approved base distribution rates

243 For Fitchburg's gas division, the RDM adjustment reconciliation will occur semi-annually.

and, therefore, 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 revenue decoupling is designed to ensure that a distribution company's 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 gas and electric revenue decoupling mechanisms that we have approved for Fitchburg will reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. See D.P.U. 10-114, at 365; D.P.U. 10-70, at 281; D.P.U. 09-30, at 367, 371-372; D.P.U. 07-50-A at 72-73.

As noted above, certain of the companies in Fitchburg's and the Attorney General's proxy groups have some form of revenue decoupling in place (Exh. Sch. SCH-1, at 2-3). 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 (Exhs. AG-7-1, Att. B at 26, 55, 99, 141, 149, 249 (electric); AG-6-1, Att. B at 26, 55, 99, 141, 149, 249 (gas)). However, the fact that approximately half of the companies in the Company's and Attorney General's proxy groups use some form of revenue stabilization mechanism does not mean that the proxy groups fully match the risk profile of the Company with respect to its proposed decoupling mechanisms. D.P.U. 09-39, at 395-396. Accordingly, we do not accept the Company's argument that there is no need to consider the equity cost impact of revenue decoupling because companies in its comparison group employ some form of revenue decoupling. In fact, we are not convinced that the comparison groups fully capture the risk-reducing impact of the Company's revenue decoupling mechanisms. Instead, we will consider the risk profile of the Company and the specific features of the revenue decoupling proposals that we are approving today to arrive at the appropriate determination of the effect on risk on Fitchburg's required ROE.

E. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 679, 692-693 and Hope at 603. The allowed ROE should preserve the Company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603, 605. It should be determined "having regard to all relevant facts." Bluefield at 692.

In support of its calculations of an appropriate ROE, Fitchburg has presented analyses using the DCF and risk premium models, incorporating the financial data of its proxy group. The Attorney General has presented her own analyses using the DCF model and CAPM, incorporating the financial data of her electric proxy group and her gas proxy group. 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 in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 114; 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 proxy group of companies could provide results that may, or may not, be reliable for the purpose of setting the Company's ROE. We note, for example, the limitations of the DCF model, used by both Fitchburg and the Attorney General, including the traditional assumptions that underlie the Gordon form of the model. Moreover, we also note, the CAPM relied upon by the Attorney General is limited both by the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums.

As noted above, we recognize that the revenue decoupling mechanisms we have approved in this case will reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. See D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although certain of the companies in the proxy groups used by Fitchburg and the Attorney General have some form of revenue stabilization or decoupling mechanism in place, the degree of revenue stabilization varies among the companies in the proxy groups and, on the whole, is not as comprehensive as the decoupling mechanism approved for the Company in this Order (see Exh. Unitil-SCH-1, at 2-3).

Further, we note that a portion of the revenues of the companies in Fitchburg's utility proxy group and the Attorney General's gas proxy group is derived from unregulated and competitive lines of business (Exhs. AG-6-4, Att. (gas); AG-7-1, Att. A (electric); Unitil-AG-1-1 (electric)).[244] This mix of regulated and unregulated operations could skew the risk profile of the regulated electric and gas distribution operations of the Company as compared to the companies in the proxy groups in a manner that would tend to overstate the proxy groups' risk profiles relative to that of the Company. In addition, certain of the electric companies included in the Company's and Attorney General's proxy groups are vertically-integrated companies. Such companies must bear the additional risk inherent in the ownership of electric generation unlike Fitchburg which owns no generation. See D.P.U. 95-40, at 96 (1995); D.P.U. 92-78, at 110. We will consider such risk differentials in determining the Company's 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;

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[244] For example, two of the companies in the Attorney General's gas proxy group are engaged in gas marketing (Exh. Unitil-AG-1-1 (electric)). One gas company which is in both the Company's proxy group and Attorney General's gas proxy group, is engaged in natural gas brokering and the sale of gas-fired heating equipment and propane (Exh. AG-7-1, Att. A, at 22 (electric)).

D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also 375 Mass. 1, 15.[245] The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

In determining the allowed ROE, the Department has considered Fitchburg's use of fully reconciling mechanisms to recover Fitchburg's actual costs for certain cost categories outside of base rates. Fitchburg presently has in place fully reconciling mechanisms for a range of expense categories, including demand-side management and residential assistance programs, pension and PBOP expense, low-income assistance, and supplier-related bad debt (Exhs. Unitil-MHC-1, at 14 (electric); Unitil-MHC-1, at 12 (gas)). As a result of this Order, Fitchburg will retain these reconciling mechanisms and implement revenue decoupling, along with an AGCE mechanism. The use of the types of reconciling mechanisms that are approved by the Department in this Order or currently in place for Fitchburg produces a more timely and predictable recovery of costs compared to traditional ratemaking. By shortening the time between when Fitchburg incurs costs and when it recovers those costs in rates, the reconciling mechanisms reduce the possibility of earnings volatility. These financial benefits will lower the business risk for Fitchburg, which would tend to reduce the risk premium that prospective investors place on the Company.

[245] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

Finally, there are other factors that we consider in determining the allowed ROE in this case related to Fitchburg's failure to meet its fundamental service obligation as a franchised utility. The Department has previously found that where there is a range of appropriate returns, both qualitative and quantitative factors must be taken into account. See, e.g., 375 Mass. 1, 11; Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, at 305-306 (1971); D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase One) at 224-225. Specifically with respect to a company's performance, we have determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. Thus, 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., D.P.U. 10-114, at 337; D.P.U. 09-39, at 400; D.P.U. 08-35, at 220; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 231; D.P.U. 92-250, at 161-162; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase One) at 224-225; D.P.U. 85-266-A/271-A at 172-173. We find no reason to depart from our long-standing precedent and the accepted regulatory practice[246] of considering qualitative factors such as management performance and customer service in setting a fair and reasonable ROE.

[246] See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); US West Communications, Inc. v. Washington Utilities and Transportation Commission, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); State of North Carolina ex rel. Utilities Commission v. General Telephone Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefor); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Public Service Corporation v. Citizen's Utility Board, Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed return on equity).

As discussed in Section V, above, the Department has found that the numerous deficiencies surrounding Fitchburg's failure to properly plan and prepare for Winter Storm 2008 constituted a failure to meet the Company's public service obligation to provide safe and reliable service. See D.P.U. 09-01-A at 3, 5, 47, 52, 60, 70 71-71, 83-84, 121, 125, 135-136. In reaching our findings in D.P.U. 09-01-A, the Department explicitly placed Fitchburg on notice that its poor Storm restoration performance would be taken into consideration during the Company's next rate case when establishing the Company's ROE. D.P.U. 09-01-A at 199.

Nonetheless, Fitchburg asserts that Winter Storm 2008 was a unique and major storm event and that a reduction in its ROE related to the Company's response to a single large storm is not justified (Company Brief at 91). As we have discussed in Section V above, but it bears repeating here, we have not been faced with a situation in which a company has so thoroughly mismanaged its response to an event like Winter Storm 2008 and compromised its responsibilities to the public so badly. For these reasons, we find that the ROE allowed the Company should be at the lower end of the reasonable range to account for Fitchburg's subpar management performance and customer service.

In addition to the Company's performance regarding Winter Storm 2008, the Attorney General asserts that Fitchburg's allowed ROE also should take account what she contends is a pattern of significant mismanagement over numerous years (Attorney General Brief at 6-7, 155, 170-171). We agree with the Attorney General that Fitchburg has shown a pattern of subpar management performance in various areas dating back to at least 1999. See Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A (2001) (double collection of gas inventory finance charges); D.T.E. 02-24/25 (subpar management performance in terms of regulatory support); D.P.U. 09-09 (unauthorized gas procurement practices).[247] However, as discussed above, we have already set Fitchburg's ROE at the lower end of the range of reasonableness as a result of its management performance with respect to Winter Storm 2008. To set Fitchburg's allowed ROE lower to take into account these additional management deficiencies could risk the Company's ability to access capital, thereby making it even more difficult for the Company to meet its essential public service obligation. Accordingly, we decline to make a further adjustment to ROE. However, we fully expect that the Company's pattern of poor management performance will end here.

[247] The Department has previously taken the Company's management performance into effect in setting the allowed ROE. D.T.E. 02-24/25, at 231.

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 9.20 percent is within a reasonable range of rates that will preserve the Company's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 10-114, at 341; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134; Blackstone Gas Company, D.T.E. 01-50, at 28 (2001). Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 10-114, at 342; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 135. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption in consideration of price and non-price social, resource, and environmental factors.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 10-114, at 342; D.P.U. 09-39, at 402; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 135.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of the company's total costs to each rate class through an embedded allocated 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.P.U. 10-114, at 342; D.P.U. 09-39, at 402; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

There are four steps to develop a COSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen and to sum these allocations in order to determine the total costs of serving each rate class. D.P.U. 09-39, at 402-403; D.T.E. 03-40, at 366-367; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 136; D.T.E. 98-51, at 131-132; D.P.U. 96-50 (Phase I) at 133-134.

The results of the COSS are compared to the revenues collected from each rate class in the test year. 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 the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are great, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 09-39, at 403; D.T.E. 02-24/25, at 253-254; D.T.E. 01-56, at 136; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs but also explicitly considers the effect of its rate structure decisions on customers' bills and the Department's goals with respect to rate structures. For instance, the pace at which fully cost based rates are implemented depends, in part, on the effect of the changes on customers. For example, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low income customers and considers the effect of such rates and rate changes on low income customers. D.P.U. 09-39, at 403-404; D.T.E. 03-40, at 367; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 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 work to decrease inter-class subsidies unless a clear record exists to support – or a statute requires – such subsidies. See, 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.P.U. 09-39, at 404; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 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 should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.P.U. 09-39, at 404; D.T.E. 03-40, at 368; D.T.E. 02-24/25, at 254-255; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30. Rate design is particularly important with respect to the goals of achieving efficiency in customer consumption decisions.

B. Electric Cost Allocation

1. Introduction

Fitchburg performed an allocated COSS for its electric division in order to assign to each of its rate classes the proper cost for each component of the Company's overall cost of service (Exh. Unitil-PMN-1E at 4). Fitchburg's allocated COSS reflects distribution revenue requirements only (Exh. Unitil-PMN-1E at 7).

The Company assigned costs to each rate class based on one of the following four methods: (1) direct assignment (e.g., test year revenues); (2) a special study designed to replicate the intended use of a specific plant investment or expense and then assigning that cost based on the specific use of that asset in the test year; (3) an external allocator that assigns costs using an allocation factor that is developed outside of the COSS (e.g., number of bills produced for each customer class in the test year); and (4) an internal allocator, which involves using some combination of costs previously allocated in the COSS to allocate remaining costs that have not yet been allocated (e.g., property taxes were allocated based on the internal PLANT allocator, which is composed of the sum of each individual item of plant in service, each of which has been previously allocated) (Exh. Unitil-PMN-1E at 6-7).

Certain distribution asset costs were allocated based on a combination of factors that reflect load diversity across the Company's distribution system (Exh. Unitil-PMN-1E at 7). Substations were allocated based on the average of the twelve-month coincident peak[248] ("12CP") demands and class peak demands (Exh. Unitil-PMN-1E at 7). The costs for line transformers were allocated based on the average of the class peaks and sum of the individual customer maximum demands (Exh. Unitil-PMN-1E at 8).

Fitchburg currently has two customers under special contracts for electricity service (Exh. Unitil-PMN-1E at 12). For the purpose of the COSS, the loads associated with these two customers were excluded from the load data that was used to design rates (Exh. Unitil-PMN-1E at 12). In addition, the revenues collected in the test year from these special contracts were credited against the overall revenue requirement, while the costs to serve the special contract customers were not specifically identified (Exh. Unitil-PMN-1E at 12-13). The Company determined a total distribution revenue requirement of $21,107,421 (Exh. Sch. PMN-1E-2, at 2).

2. Position of the Attorney General

The Attorney General argues that the Company's COSS over-allocates certain costs to the residential rate class (Attorney General Brief at 179). In addition, the Attorney General

[248] Coincident peak is commonly defined as the energy demand by a rate class during periods of peak system demand.

claims that the COSS contains a number of errors and problems (Attorney General Brief at 179-180). First, the Attorney General avers that the service plant allocator is overstated because the Company inadvertently included the cost of a meter in the calculation, an error admitted by the Company (Attorney General Brief at 180, citing Exh. AG-12-7 (electric)). Second, the Attorney General contends that the allocation of underground service costs for the residential rate class includes the costs of underground conductors, while the general service underground service allocation does not (Attorney General Brief at 180). Third, the Attorney General claims that the allocation weights for underground service costs to rate classes GD-1 and GD-2 contain an error in the labor costs (Attorney General Brief at 180). Fourth, the Attorney General contends that the service allocator incorrectly assigns the cost of overhead and underground services to each rate class (Attorney General Brief at 180). The Attorney General notes that the Company conceded that its original assumptions were incorrect and ultimately corrected the assignment for overhead and underground service costs to each rate class (Attorney General Brief at 180, citing Exh. AG-12-9 (electric)). The Attorney General argues that these errors and problems should be corrected when the Company re-runs its COSS for its electric division (Attorney General Brief at 182).

Next, the Attorney General argues that transformer costs were allocated incorrectly in the COSS (Attorney General Brief at 180). The Attorney General contends that transformer costs should have been allocated using class non-coincident peaks ("NCP"), rather than blending NCP with customer maximum demand, which is how the Company allocated transformer costs (Attorney General Brief at 180). The Attorney General contends that including the sum of maximum customer demands in the allocation of transformer costs moves the allocation of these costs further from cost causation because the sum of maximum demands for the residential rate classes is a greater multiple of the class non-coincident peak than the sum of maximum demands of the GD-2 rate class is to its non-coincident peak (Attorney General Brief at 180-181, citing Exh. AG-LS-1, at 7-8 (electric)).

Finally, the Attorney General argues that substation costs have been improperly allocated in the COSS (Attorney General Brief at 181). The Attorney General contends that substation costs should have been allocated using just the 12 CP rather than blending the 12 CP with the sum of the NCPs, which is how the Company allocated substation costs (Attorney General Brief at 181). The Attorney General contends that only the 12 CP should be used to allocate substation costs because Fitchburg is essentially a dual-peaking system (i.e., the summer peak and winter peak for the system are similar), so the peaks in all months contribute to cost causation for substations (Attorney General Brief at 181-182).

Neither the Company nor any other party addressed the Company's electric division allocated COSS on brief.

3. Analysis and Findings

The Attorney General has documented a number of issues with regard to the service plant allocator calculations in the Company's electric COSS. The Company has acknowledged two of these issues. First, the Company accepts that the meter cost was inadvertently included when calculating the service cost by customer class (Exh. AG-12-7 (electric)). Second, the

Company included estimates for the breakdown of overhead versus underground service in its original filing as the Company states that actual survey data were not available at the time of the filing (Exh. AG-12-9 (electric)). Fitchburg subsequently provided survey data for overhead and underground service breakdowns for residential and commercial customers (Exh. AG-12-9 (electric)).

Regarding the remaining issues raised by the Attorney General, the Department finds that the Company should include the costs of the underground conductor when calculating the percent of underground service costs to assign to both the residential and the general service rate classes. The inclusion of these costs is consistent with the Company's terms for the installation of underground service (RR-DPU-67, Att. 1, at 21-23 (proposed M.D.P.U. No. 195)). With respect to the labor costs included in the calculation of underground service costs for rate GD-2, the Attorney General notes that the labor involved to perform a service connection for rate GD-2 appears to be very similar to the labor involved to perform a service connection for rate GD-1 (see Exh. AG-12-8, Att. 1, at 11, 14 (electric)). However, the labor cost listed for rate GD-2 is $292 (based on one hour of labor), while the labor costs listed for rate GD-1 it is $1,748 (based on six hours of labor) (see Exh. AG-12-8, Att. 1, at 11, 14 (electric)).[249] The Company has provided no evidence to explain or support why these values should be different. The Department can find no reason to conclude that a service installation for a medium commercial customer (GD-2) would take one-sixth the time of a service

[249] The hourly labor rate for the GD-1 and GD-2 service installations is $292 per hour (Exh. AG-12-8, Att. 1, at 11, 14 (electric)).

installation for a small commercial customer (GD-1). Consequently, when re-running the COSS for the purpose of complying with this Order the Company is directed to use the labor cost used for the rate GD-1 calculation when calculating the cost of an underground service connection for rate GD-2.

The Attorney General also contested the method the Company used to allocate transformer costs in its COSS. The Attorney General argues that transformer costs should be allocated using class NCP, rather than a blending of NCP and customer maximum demand (Attorney General Brief at 180). In D.P.U. 09-39, at 413, the Department found that the NCP allocation method most accurately captures the drivers behind transformer costs and was superior to a hybrid method proposed by the petitioners in that matter. The Company has not provided us with any reasons to justify a departure from that precedent. Therefore, when running the COSS in order to comply with this Order, the Company is directed to allocate transformer costs based on the NCP allocation method.

The Attorney General also raised concerns with the allocation of substation costs in the COSS. The Attorney General avers that substation costs should be allocated based on the 12 CPs for each rate class, rather than a blending of the 12 CPs with the sum of the NCPs for each rate class (Attorney General Brief at 181). The Department agrees with the Attorney General. Allocating substation costs using the 12 CP method is a simpler approach that provides a reasonable level of accuracy for the purpose of the COSS. Therefore, when running the COSS in order to comply with this Order, the Company is directed to allocate substation costs based on the 12 CP allocation method.

With the modifications outlined above, the Department finds that the Company's proposed electric COSS is reasonable and consistent with Department precedent. D.P.U. 10-70, at 296-297; D.P.U. 09-39, at 413. Accordingly, with such modifications, we accept Fitchburg's electric COSS.

C. Gas Cost Allocation

1. Introduction

Fitchburg performed an allocated COSS for its gas division in order to assign to each of its rate classes the proper cost for each component of Fitchburg's overall cost of service (Exh. Unitil-PMN-1G at 8). Fitchburg ran three separate allocated COSS (Exh. Unitil-PMN-1G at 2). The first allocates total company costs (Exhs. Unitil-PMN-1G at 2; Sch. PMN-1G-2). The second allocates costs related solely to the delivery function (Exhs. Unitil-PMN-1G at 2; Sch. PMN-1G-3). The third allocates costs related solely to supply (Exhs. Unitil-PMN-1G at 2; Sch. PMN-1G-4).

As for its electric COSS, the Company assigned costs to each rate class based on one of the following four methods: (1) direct assignment (e.g., test year revenues); (2) a special study designed to replicate the intended use of a specific plant investment or expense and then assigning that cost based on the specific use of that asset in the test year; (3) an external allocator that assigns costs using an allocation factor that is developed outside of the COSS (e.g., number of bills produced for each customer class in the test year); and (4) an internal allocator, which involves using some combination of costs previously allocated in the COSS to allocate remaining costs that have not yet been allocated (e.g., property taxes were allocated based on the internal PLANT allocator, which is composed of the sum of each individual item of plant in service, each of which has been previously allocated) (Exh. Unitil-PMN-1G at 10-11).

The Company determined a total distribution revenue requirement of $15,155,711 (Exh. Sch. PMN-1G-5, at 21). No party raised any issues regarding the Company's COSS for its gas division.

2. Analysis and Findings

No issues were raised by any parties regarding the Company's gas COSS. The Department has reviewed Fitchburg's gas COSS and finds it to be reasonable and consistent with Department precedent. D.P.U. 10-70, at 291-292; D.P.U. 09-39, at 413. Accordingly, we accept Fitchburg's gas COSS.

D. Marginal Cost Study – Gas Division

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 10-55, at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on 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. 10-55, at 524; D.P.U. 09-30, at 378; D.P.U. 08-35, at 227; D.P.U. 07-71, at 159. In support of its rate case filing, Fitchburg prepared a marginal cost study ("MCS") for its gas operations (Exhs. Unitil-PMN-1G at 24-40; Unitil-PMN-2G-1 through Unitil PMN-2G-9).[250]

[250] Fitchburg also prepared a marginal cost study for its electric division (Exhs. Unitil-PMN-1E at 16-35; Unitil-PMN-2E-1 through Unitil-PMN-2E-6). No party raised any issues with respect to that filing.

Fitchburg estimated the marginal costs to serve each of its rate classes based on rate year costs (Exh. Unitil-PMN-1G at 26).[251] First, the Company used the peaker method to estimate production capacity costs related to distribution pressure support (Exh. Unitil-PMN-1G at 26). Next, Fitchburg applied regression techniques to estimate the hypothetical capacity-related distribution costs of serving an increment of customer load, including the unit costs of adding distribution plant facilities as well as the additional costs for O&M (Exh. Unitil-PMN-1G at 26). Finally, the Company developed the annual distribution capacity-related revenue requirements to serve each of Fitchburg's gas rate classes (Exh. Unitil-PMN-1G at 26). In order to measure capacity costs the Company chose the design day as it represents the load on the coldest day for which the Company must provide reliable firm service (Exh. Unitil-PMN-1G at 26).

To develop the MCS, the Company estimated the investment necessary for manufactured gas facilities to provide pressure support on the distribution system (Exhs. Unitil-PMN-1G at 27; Sch. PMN-2G-1). Next, the Company addressed the

[251] The Company states that the MCS excludes production, transmission and customer costs, as they are not relevant to the design of distribution rates (Exh. Unitil-PMN-1G at 25-26).

capacity-related distribution plant investments, excluding customer-related investments to serve growth (Exhs. Unitil-PMN-1G at 27; Sch. PMN-2G-2). Third, Fitchburg derived O&M expenses related to the production facilities used for distribution pressure support and calculated the marginal distribution capacity-related O&M expenses (Exhs. Unitil-PMN-1G at 27-28; Sch. PMN-2G-3; Sch. PMN-2G-4). Fourth, the Company identified the delivery-related uncollectible levels for each rate class taken from the accounting cost study (Exhs. Unitil-PMN-1G at 28; Sch. PMN-2G-5). Fifth, Fitchburg developed loading factors from marginal costs that were not individually estimated,[252] translated a one-time capital investment into annual revenue requirements, and quantified the system's marginal distribution capacity costs per decatherm ("Dth") of design day demand (Exhs. Unitil-PMN-1G at 28; Sch. PMN-2G-6; Sch. PMN-2G-7; Sch. PMN-2G-8). Finally, Fitchburg converted the unit capacity costs into total marginal costs to serve each class, which it then divided by billing units to derive marginal cost-based prices (Exhs. Unitil-PMN-1G at 28; Sch. PMN-2G-9).

To develop the production plant capacity costs, the Company first identified the cost of expanding its existing LP-air peaking facility as its least capital intensive alternative to add peaking capacity (Exh. Unitil-PMN-1G at 29). The Company used the modified peaker approach to calculate long-run marginal capacity costs (Exh. Unitil-PMN-1G at 29). The Company relied on econometric models specified using multi-variate regression techniques and used 31 years of historical data to develop the proposed marginal distribution capacity costs

[252] Marginal costs not individually estimated include administrative and general expenses (Exh. Unitil-PMN-1G, at 28).

(Exh. Unitil-PMN-1G at 30). According to Fitchburg, the relevant statistics of the Company's econometric models indicate the robustness of the models (Exh. Unitil-PMN-1G at 33, 35). No party addressed the results of the Company's gas division MCS.

2. Analysis and Findings

We find that the MCS developed by Fitchburg incorporates sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. Consistent with the directives in D.T.E. 05-27 at 322 & n. 170, the Company has excluded from its marginal cost study all production, transmission and customer costs (Exh. Unitil-PMN-1G at 25-26). Further, we find that the Company has used reliable data to develop the MCS, as required by Department precedent. D.T.E. 03-40, at 377.

In accordance with the directives of D.P.U. 07-71, at 164, Fitchburg used proper econometric techniques to provide a statistically reliable estimate of the marginal O&M expense (Exhs. Unitil-PMN-1G at 33-35; Sch. PMN-2G-1 through PMN-2G-9). For example, the adjusted R-Squared of the regression for growth-related capacity-related investment in distribution plant was .9163 (Exhs. Unitil-PMN-1G, at 33; Sch. PMN-2G-2, at 1). Further, Fitchburg used 31 years of historical data in its regression analysis, encompassing the period 1979 to 2009 (Exhs. Unitil-PMN-1G, at 30; Sch. PMN-2G-2). The Company also used multi-variate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions in its MCS (Exhs. Unitil-PMN-1G at 30; Sch. PMN-2G-2, at 1). Based on the foregoing, we conclude that, consistent with D.P.U. 07-71, at 164, Fitchburg used the most robust MCS model available. Based on these findings, the Department accepts Fitchburg's gas marginal costs estimated from the econometric analyses.

E. Electric Rate Design

1. Introduction

The Company examined the results of the COSS in order to determine the revenue requirement for each rate class (Exh. Unitil PMN-1E at 36-37). The Company compared the revenue requirement for each class at existing revenues with the revenue requirement at the proposed rates at an equalized rate of return, as shown in the COSS (Exh. Unitil-PMN-1E at 36-37).

Rather than applying the revenue increases for each rate class that were prescribed by the COSS, Fitchburg proposes to apply a uniform increase of 30.59 percent to all rate classes (Exh. Unitil-PMN-1E at 39). With the exception of the outdoor lighting rate class, Fitchburg states that the increases at equalized rates of return as prescribed by the COSS are reasonably close to the average overall increase for most rate classes (Exh. Unitil-PMN-1E at 37). However, in order to satisfy the Company's goal of mitigating rate impacts, Fitchburg chose to apply a uniform increase (Exh. Unitil-PMN-1E at 39).

When designing rates for the individual rate classes, the Company used a five step process (Exh. Unitil-PMN-1E at 39). First, the class revenue target was established by applying the uniform increase referenced above and subtracting the allocated special contract revenues (Exh. Unitil-PMN-1E at 39). Second, the rate structure for each rate class (i.e., flat rates versus inclining-block rates, or revenue recovery through both energy and demand charges versus an energy charge alone) was determined (Exh. Unitil-PMN-1E at 39). Third, customer charges were established (Exh. Unitil-PMN-1E at 39). Fourth, tail block prices were derived (Exh. Unitil-PMN-1E at 39). Fifth, head block rates were derived to recover the residual revenue requirement assigned to that class (Exh. Unitil-PMN-1E at 39).

The Company states that it considered the embedded customer costs from the COSS and Department precedent when proposing customer charges (Exh. Unitil-PMN-1E at 40-41). The Company proposes to decrease the customer charge for rate GD-3 and keep the customer charges for all other rate classes unchanged (Exh. Sch. PMN-1E-6, at 3). Customer charges are discussed further below.

The Company proposes to implement inclining block rates for rate RD-1, rate RD-2, rate GD-1 and rate GD-5 (Exh. Unitil-PMN-1E at 40). Fitchburg's proposed rate design for rates RD-1 and RD-2 produces tail block rates that are 33 percent higher than the head block rates (Exh. Unitil-PMN-1E at 41). The Company states that it established the size of the rate blocks by approximating the average usage level of a typical customer in that rate class (Exh. Unitil-PMN-1E at 40). For rate RD-1 and rate RD-2, the Company set the block break at 600 kWh (Exhs. Unitil-PMN-1E at 40; Sch. PMN-1E-6, at 1). For rate GD-1, the Company set the block break at 200 kWh (Exhs. Unitil-PMN-1E at 40; Sch. PMN-1E-6, at 1). For rate GD-5, the Company set the block break at 2,500 kWh (Exhs. Unitil-PMN-1E at 40; Sch. PMN-1E-6, at 1). The Company's rate design proposal for each rate class is discussed in further detail below.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed rate design is not consistent with the Department's rate design objectives (Attorney General Brief at 183). The Attorney General contends that the Company's proposal to introduce inclining-block rates but maintain or, in one instance, lower existing customer charges is inconsistent with the Department's rate design goals of rate continuity and equity, and does not provide ratepayers with the correct price signals (Attorney General Brief at 183). Further, the Attorney General claims that the combination of the proposed customer charges, the proposed block breaks for the inclining-block rates, and the differential between the head block and the tail block result in disparate bill impacts within rate classes (Attorney General Brief at 184).

The Attorney General proposes an alternative rate design for the residential rate class that includes a modest increase to the residential customer charge from $5.29 to $6.00, and inclining-block rates with a tail block rate that is five percent higher than the head block rate (Attorney General Brief at 185). The Attorney General contends that, under her proposal, most residential customers will experience an increase to their total bill of approximately eleven percent, which is higher than the bill impacts under the Company's proposal, but is not extreme (Attorney General Brief at 185).

In addition, the Attorney General raises several concerns with respect to the Company's presentation of its low income bill (Attorney General Brief at 190-191). The Attorney General contends that because some rate elements are discounted in a different fashion than others, customers have no way to determine the accuracy of their bills without contacting the Company (Attorney General Brief at 190). According to the Attorney General, the Department's regulations are clear that customers are entitled to receive bills that are complete, understandable, and provide sufficient information that would allow them to validate the charges for which they are responsible (Attorney General Brief at 191, citing 220 C.M.R. § 5.02 (3)(b)). Therefore, the Attorney General asserts that the Department should require the Company to modify its low income bill to include a section that identifies the charges under the non-low income residential rates, the discount percentage, the dollar amount of the discount, and the resulting low income rate (Attorney General Brief at 191). In addition, the Attorney General submits that the Company should revise its low income tariff to include clear language explaining how the low income bills are calculated and to identify the discount rate (Attorney General Brief at 191).

b. DOER

DOER takes issue with the alternatives set forth by the Attorney General (DOER Brief at 8 (electric)). First, DOER states that the Department should reject the Attorney General's proposal for a flat energy charge as it is inconsistent with recent Department directives pertaining to inclining block rates (DOER Brief at 8 (electric)). Second, because the Attorney General's alternative inclining-block rate design results in tail block rates that are a mere three mills higher than the headlock rates, DOER disputes the effectiveness of this alternative for the purpose of promoting energy conservation (DOER Brief at 8-9 (electric)). DOER recommends that the Department reject the Attorney General's proposals with respect to inclining-block rate design and, instead, approve an inclining-block rate structure in this proceeding that is similar to those previously approved in recent rate proceedings (DOER Brief at 9 (electric) citing D.P.U. 10-70; D.P.U. 09-39; D.P.U. 09-30).

c. Fitchburg

Fitchburg rejects the Attorney General's assertion that the Company's low income bills are confusing to customers (Company Brief at 124). The Company argues that, in recent low income related dockets the Department did not find it necessary to consider a bill presentation requirement similar to that proposed by the Attorney General in the instant cases (Company Brief at 124, citing D.P.U. 10-41; D.P.U. 08-4). Further, the Company contends that the billing of low income customers is complicated by (1) constraints on the Company's billing system, and (2) the fact that Fitchburg discounts the transition charge and energy efficiency reconciliation factor separately from the low income discount (Company Brief at 124-125).

Fitchburg also disputes the Attorney General's contention that the Company's low income tariffs are unclear (Company Brief at 125). Fitchburg argues that its summary tariff clearly shows the calculation of the low income discount by rate component (i.e., customer charge, delivery charges, and supply charges) (Company Brief at 125). As such, the Company asserts that there is no need to modify its bills or tariffs for low income customers (Company Brief at 125).

3. Analysis and Findings

The Department must determine, on a rate class by rate class basis, the proper level at which to set the customer charge and delivery charges for each rate class, based on a balancing of our rate design goals. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 193-194; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance its goal of fairness with its goal of continuity. To arrive at this balance, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes. Based upon our review, we accept the Company's proposal whereby all rate classes shall receive a uniform increase based on the total increase prescribed by the COSS (Exh. Unitil-PMN-1E at 39). The Department finds for this particular case that a uniform increase meets our rate structure goals by ensuring that: (1) the final rates for each rate class represent or approach the cost to serve that class; (2) the limited level of cost subsidization created by the uniform increase will not unduly distort rate efficiencies; and (3) the magnitude of change to any one class is contained within reasonable bounds (Exh. Unitil-PMN-1E at 37). The Department directs Fitchburg to provide, in its compliance filing, a copy of its COSS results, incorporating all of the costs approved in this proceeding. In addition, to determine the portion of the revenue requirement to be collected from each rate class, the Department directs the Company to apply the total percentage increase prescribed by the COSS to all rate classes, as illustrated on Schedule 10.

Regarding the proposed customer charges for all rate classes, the Department has examined the embedded customer cost information from the COSS and the bill impacts that will result from these proposed customer charges (Exhs. Sch. PMN-1E-4, at 4; Sch. PMN-1E-7). The Department is mindful of the goal of balancing economic efficiency with the goal of sending the proper price signals for end-use efficiency. The Department also must consider the financial impacts that changes to the customer charge will have on low-use customers. Based on the evidence and the balancing of these goals, the Department finds that the Company's proposed customer charges are reasonable. Maintaining the customer charges at their current rates (for all rates except rate GD-3) so that the revenue increase will be recovered through the volumetric charges best balances our rate design goals in that it will send a stronger price signal to customers to conserve electricity. The Department will specify what the customer charge shall be for each rate class in Section XII.G, below.

In D.P.U. 08-35, at 249, the Department found 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, the Department has found that rates should have an inclining block rate structure and any resulting loss in revenues from declining sales should be recovered through a decoupling mechanism. D.P.U. 08-35, at 249. Fitchburg has included inclining block rates as part of its proposed residential and small commercial rate design. Fitchburg has designed inclining block rates with a meaningful differential between the head block and tail block rates and with block breaks set such that high use customers will be sent a price signal to conserve electricity. Therefore, the Department finds that Fitchburg's proposed inclining block rate design comports with Department precedent. See D.P.U. 08-35, at 249; D.P.U. 07-50-A at 25-28.

The Department declines to accept the Attorney General's residential rate design proposal. The Attorney General's proposed residential rate design would increase the customer charge and establish inclining block rates that include tail block rates set at five percent higher than the head block rates. Increasing the customer charge would be contrary to recent Department precedent, wherein the Department stated its preference to set the customer charge at a level that allows for the recovery of more revenues through the volumetric charges. D.P.U. 10-70, at 328.

Regarding the Company's low income tariff and low income bill presentation, the Department is not persuaded by the Attorney General's arguments that the low income tariff is in need of modification. Fitchburg's currently effective low income tariff (M.D.P.U. No. 192), which took effect February 1, 2011, sets forth the discount to which low income customers are entitled (24.8 percent).

The Company has stated that the transition charge for low income customers is discounted by $0.00327 per kWh, pursuant to the D.T.E. 05-29 settlement

(Exh. AG-11-3 (electric)). Because this rate is already discounted, the Company removes this charge (and the energy efficiency reconciliation factor ("EERF")) from the calculation of the low income discount so as not to discount these rates twice (RR-DPU-8). However, comparing the current transition charge for non-low income customers, $0.02420 per kWh, to the current transition charge for low income customers, $0.02039 per kWh, the transition charge for low income customers is only 13.5 percent lower than the transition charge for non-low income customers. As stated in Section XII.G below, low income customers are entitled to a 25 percent discount on all bill components. The Department finds that Fitchburg shall restore the transition charge for low income customers to the same level as the transition charge for non-low income customers ($0.02420 per kWh). That transition charge shall then be discounted by 25 percent for low income customers, as it is for all other rate elements.

Regarding the bill for low income customers, this bill already includes the non-low income rates and the percentage discount to which customers are entitled (RR-DPU-8, Att. 1). While we agree that the presentation of the calculation of the discount amounts could be clearer, the Company must work within the constraints of its billing system. Much of the confusion is caused by the fact that the Company discounts the transition charge and the EERF for low income customers by a different amount than the low income discount. We have addressed this issue with regard to the transition charge above. The Department will address the issue of the discounting of the EERF in the ongoing EERF dockets (see docket D.P.U. 10-06/07/08/09). The fact that these charges are already discounted makes it difficult to present a simple calculation of the discount that is received by customers. While the Department finds that it is not necessary for Fitchburg to take any additional action at this time regarding its low income tariff or low income bill, the Department is generally concerned with the presentation of bills for all rate classes. There has been a significant increase in the number of charges to which ratepayers are subject, and the Department is concerned about whether electric and gas distribution companies are presenting these charges on bills in a manner that is easily understood by ratepayers. The Department intends to address this issue for all electric and gas distribution companies in the near future.

F. Transition Charge Mitigation Proposal

1. Introduction

The transition charge was established pursuant to the 1997 Electric Restructuring Act[253] ("Restructuring Act") to allow companies to recover "stranded costs" related to the restructuring of the electric utility industry in Massachusetts. See G.L. c. 164, § 1G.[254] Fitchburg has recovered these costs, with carrying charges, since 1998. Fitchburg Gas and Electric Light Company, D.T.E. 97-115, at 10-12 (1998). Pursuant to a settlement in Fitchburg Gas and Electric Company, D.T.E. 01-103-A (2002), the carrying charge was reset

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253 An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Customer Protection Therein, St. 1997, c. 164.

254 "Stranded costs" are the costs of investments in generation-related assets and other obligations undertaken by electric distribution companies in reliance upon the pre-existing regulatory scheme prior to electric restructuring. See G.L. c. 164, § 1G.

at 9.05 percent on the cumulative balance of transition charge over-or under-recoveries subject to reconciliation, effective January 1, 2003.[255] The carrying charge currently remains at this level.

In the instant proceedings, Fitchburg proposes to offset the requested electric distribution revenue increase with a corresponding deferral of the Company's transition charge (Exh. Unitil-MHC-1, at 5-6 (electric)). The Company did not propose a similar mechanism to offset the requested distribution rate increase for its gas division (see Exh. Unitil-PMN-1G at 40-44).

Under the Company's proposal, the uniform transition charge would be reduced by $0.01621 per kWh to $0.00799 per kWh for the remainder of the transition cost recovery period (Exh. Unitil-MHC- 1, at 6 (electric)). The Company's proposal would result in deferred transition costs which will be recovered in subsequent years with carrying charges (as discussed below) (Exh. DPU-14-5 (electric)).

Further, the Company seeks to establish the head and tail block rates in such a manner as to ensure no bill impact to the residential customer using 600 kWh or less of electricity per month (Exh. Unitil PMN-1E at 41). In order to achieve this rate design goal, Fitchburg adds the Company's proposed storm recovery adjustment factor of $0.00500 per kWh to the Company's proposed transition charge deferral (-$0.01621 per kWh) to obtain a net decrease of $0.01121 per kWh (Exh. Unitil-PMN-1E at 41). Assuming the proposed customer charges

255 From 1998 through 2000, the Company applied a carrying charge of 12.45 percent to the fixed component of its transition charge. D.T.E. 01-103-A at 2 n.4.

are unchanged, the head block increases by $0.01121 to $0.05664 with no impact on the total bill for any residential customer using less than 600 kWh of electricity per month (Exh. Unitil-PMN-1E at 41). The remaining revenue requirement would be recovered through the tail block rate (Exh. Unitil-PMN-1E at 41).

Under Fitchburg's proposal, the recovery of transition costs would be deferred and the Company would recover these costs in subsequent years to the extent that there is room for recovery under the transition charge rate cap of $0.02420 per kWh (RR-DPU-7, Att. 1, at 12; see also Fitchburg Gas and Electric Light Company, D.T.E. 97-115/98-120, at 58 (1999)).[256] Absent a reduction in the transition charge, the Company expects to recover all transition costs by 2014 (Exhs. Unitil-MHC-Rebuttal-2, at 15; AG-8-38, Att. 1 (electric)). However, the transition charge recovery period is forecasted to extend beyond 2014 if the Company's deferral proposal is allowed (Exh. Unitil-MHC-Rebuttal-2, at 16; Tr. 15, at 1924-1925).

Initially, the Company proposed to apply the 9.05 percent carrying charge, which was established in the D.T.E. 01-103-A settlement, to the recovery of the transition costs for the entire transition charge recovery period (see Exhs. Unitil-MHC-Rebutal-2, at 15-16; DPU-14-5 (electric)). However, during the course of the proceedings in the instant case, Fitchburg modified the carrying charge component of its deferral proposal. Specifically, the Company now proposes to apply a carrying charge of 9.05 percent only through the end of 2014; but

[256] Under the terms of the settlement approved in Fitchburg Gas and Electric Light Company, D.T.E. 05-29, the Company's transition charge cannot exceed $0.02420 per kWh (RR-DPU-7, Att. 1, at 12).

post-2014 the Company would apply a carrying charge at the WACC approved in the instant proceeding for the remainder of the transition charge recovery period (Exh. Unitil-MHC-Rebuttal-2, at 15-16).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposal to offset the distribution rate increase through a reduction in the transition charge (Attorney General Brief at 142). The Attorney General contends that the Company's proposal is, "a scheme to lull ratepayers into believing no rate increase has occurred and thereby shielding the Company from public criticism" (Attorney General Brief at 142). The Attorney General also claims that the Company's proposal, due to the recovery of all deferred transition costs with carrying costs, is nothing more than a new profit center for the Company (Attorney General Reply Brief at 52).

Further, the Attorney General argues that the Company's proposal runs contrary to the legislative intent associated with the creation of the transition charge (Attorney General Brief at 142-143). According to the Attorney General, the transition charge was intended to be a temporary measure through which stranded costs related to electric utility restructuring would be recovered (Attorney General Brief at 143-144). The Attorney General argues that the Company proposes instead to inappropriately use the transition charge to offset a distribution rate increase which is, in no way, a cost associated with the restructuring of the electric utility industry (Attorney General Brief at 143-144).

The Attorney General also argues that the Company’s proposal would come with significant costs for Fitchburg’s ratepayers in the form of carrying costs for the deferred transition costs (Attorney General Brief at 145-146). Further, the Attorney General raises the issue of intergenerational inequity with regard to transition cost recovery, as deferral of the transition charge would prolong the recovery of transition costs for an additional ten years and, therefore, there is a strong likelihood that customers who would not have benefitted from the Company’s rate mitigation proposal would be required to pay for the deferred transition costs that result (Attorney General Brief at 147-148; Attorney General Reply Brief at 52).

b. DOER

DOER argues that the Company’s proposal to offset any electric rate increase allowed in this proceeding with an equal reduction to its transition charge is bad policy (DOER Brief at 6-7 (electric)). DOER contends that the Company’s proposal is designed to mask a rate increase (DOER Brief at 7 (electric)).

DOER claims that there is a strong likelihood that the ROE allowed in this case will be less than the carrying charge allowed for transition costs (DOER Brief at 7 (electric)). In that regard, DOER avers that the Company’s proposal amounts to a deferred rate increase with an excessive carrying charge of 9.05 percent (DOER Brief at 7 (electric)). For these reasons, DOER recommends that the Department reject the Company’s proposal to offset the rate increase with a corresponding decrease to the transition charge (DOER Brief at 7 (electric)).

c. Fitchburg

The Company argues that its rate mitigation proposal is a reasonable means to mitigate rate impacts for Fitchburg's electric customers (Company Brief at 123). Although the Company provided no cites to Department precedent, the Company contends that rate deferrals have been approved by the Department in the past (Company Brief at 123-124). Further, the Company reiterates that it has revised its carrying charge proposal such that ratepayers will pay a lower carrying charge after 2014 (Company Brief at 124).[257] Finally, the Company asserts that transition cost recovery will extend until 2024 only if the Company is granted the full revenue increase that it is seeking in the instant proceeding (Company Brief at 124).

3. Analysis and Findings

The transition charge was established to allow companies to recover stranded costs related to the restructuring of the electric utility industry in Massachusetts. The transition charge was intended to be a temporary charge, the recovery of which would end when a utility recovered all Department-approved transition costs.[258]

The Company correctly notes that the Department has previously approved a postponement of a scheduled increase to the transition charge and the resulting deferral of the

[257] The Company states that, absent its rate mitigation proposal, it forecasts that it would recover all transition costs in three years (or by 2014), during which time it is entitled to the 9.05 percent carrying charge approved in the D.T.E. 01-103-A settlement (Exh. Unitil-MHC-Rebuttal-2, at 15).

[258] See G.L. c. 164, §1G(e), which states, in part: The Department shall, on a case by case basis, determine the date upon which there shall be no allowance for transition cost recovery in any rate charged by any transmission or distribution company.

collection of transition costs with carrying charges, in NSTAR Electric Company, D.T.E. 05-85, at 3, 33 (2005). However, Department approval in that case was part of a broader settlement involving multiple issues including the company's assertion that, pursuant to the settlement, it would forgo a distribution rate increase that it would otherwise be entitled to. See D.T.E. 05-85, at 3-15. The Department has not approved in a fully adjudicated rate case a proposal similar to the Company's request.[259]

We acknowledge that allowing the Company's proposal would provide short-term rate relief to Fitchburg's electric customers, particularly those residential customers using 600 kWh or less of electricity per month, as they would not experience the immediate effects of the distribution rate increase (Exh. Sch. PMN-1E-7, at 1). However, under the Company's proposal its recovery of transition costs would simply be deferred, not foregone, an effect which would not be transparent to customers. All customers would ultimately be called upon to pay these transition costs and, under the Company's proposal they would do so for a longer period of time and with more interest charges than if the transition charge was permitted to expire as currently projected in 2014 (Exhs. Unitil-MHC-Rebuttal-2, at 15; AG-8-38, Att. 1). More specifically, under the Company's proposal, customers could continue to pay the

[259] The Company's proposal in the instant case is further distinguishable from the proposal approved in the D.T.E. 05-85 settlement because there, prior to implementing the rate mitigation plan, the settlement postponed a scheduled increase in the transition charge and, instead, maintained the charge at its current level. Here, Fitchburg seeks to lower the currently effective transition charge.

transition charge for an additional ten years and at a cost of approximately $16.8 million in additional interest (Exh. AG-8-38, Atts. 1, 2; Tr. 7, at 780). Consequently, if the Company's proposal were allowed, ratepayers would pay more in the future for transition costs than they now would through an immediate rate increase (Exh. AG-8-38, Atts. 1, 2; Tr. 7, at 776-781).

In an effort to determine if Fitchburg's proposal offered any benefits to ratepayers, the Department asked the Company to consider various alternative (i.e., lower) interest rates for the deferrals resulting from the proposal (Tr. 15, at 1924-1927). The Company's response strongly suggests that the interest rate Fitchburg seeks to apply to these deferrals (i.e., 9.05 percent through 2014 and 8.50 percent thereafter), which is significantly higher than any interest rate that customers are likely to earn on their money in the current economic environment, is a "take it or leave it" proposal.[260]

In addition to these significant concerns about the ultimate cost of the Company's proposal, we find that the proposal sends an improper price signal to customers as it obscures the true cost of distribution service. Fitchburg's plan to levelize the rate for customers using 600 kWh or less of electricity per month is not based on a reduction of the Company's overall cost to serve, but on the deferral of the recovery of the transition costs. Customers should make decisions about energy usage based on complete information about what it costs to

[260] Fitchburg indicated that it would consider withdrawing its proposal if a lower carrying charge was applied to its deferrals by the Department (Tr. 15, at 1924-1927). The Company went as far as to state that it may need to come before the Department for rate relief if it is undercompensated through the transition costs carrying charge (Tr. 15, at 1926).

provide a service. If the cost for a service (distribution service, in this case) is masked by a deferral in costs elsewhere (transition costs, in this case), customers may make poor decisions regarding energy usage as a result.

Further, as the Attorney General notes, the Company's proposal raises intergenerational equity concerns. It is conceivable that future ratepayers, born after the transition charge was established in 1998, would be asked to pay a transition charge even though the charge would otherwise have expired in 2014 absent approval of the Company's proposal.

The one clear beneficiary of the Company's proposal would be the Company itself. During a time when the Company could clearly benefit from a good news story, its proposal would allow it to tell ratepayers that they will not see any bill increase as a result of its request to increase rates despite the fact that every dollar of transition costs that is deferred as a result of the Company's proposal would ultimately be paid by its ratepayers, with interest (see Exh. AG-4, at 2).

Based on all of the above considerations, we find that the Company's transition charge deferral proposal is not in the best interest of customers and, accordingly, it is rejected. In reaching this decision, and in light of our other findings in these proceedings, we are mindful that residential electric customers will experience an immediate rate increase that otherwise would have been postponed if the Company's proposal was allowed. There is seldom, if ever, a good time to increase rates. But we stress again that the Company's proposal, which lacks transparency, was not to forego a rate increase but rather to defer it, with significant costs to customers for many years in the future.

G. Electric Rate-by-Rate Analysis

1. Rates RD-1 and RD-2

a. Fitchburg's Proposal

Rates RD-1 and RD-2 are available for all domestic purposes in individual private dwellings and in individual apartments (see RR-DPU-67, Att. 1, at 43-48 (proposed M.D.P.U. Nos. 198, 199)). Rate RD-2 is a subsidized rate available to customers who are recipients of any means-tested public benefit program, 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 (RR-DPU-67, Att. 1, at 46 (proposed M.D.P.U. No. 199)). Customers who qualify for this subsidy are required each year to certify their continuing eligibility (RR-DPU-67, Att. 1, at 46 (proposed M.D.P.U. No. 199)).

Beginning February 1, 2011 the Company modified the application of the low income discount pursuant to Fitchburg Gas and Electric Light Company, D.P.U. 10-41 (2010). Consequently, the rates for rate RD-2 were reset so that they are the same as rate RD-1, and RD-2 customers receive a 24.8 percent discount off of their entire bill. M.D.P.U. No. 192.

Fitchburg proposes to maintain the current RD-1 customer charge of $5.29 for both rate RD-1 and rate RD-2 (Exh. Sch. PMN-1E-6, at 3). See also M.D.P.U. No. 210. The Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block break set at 600 kWh for both rate RD-1 and rate RD-2 (Exh. Sch. PMN-1E-6, at 1). For rate RD-1 and rate RD-2, Fitchburg proposes a head block charge of $0.05664 per kWh and a tail block charge of $0.07542 per kWh (Exh. Sch. PMN-1E-6, at 3).

b. Analysis and Findings

As described above, Fitchburg's proposed method for establishing the volumetric charges for rate RD-1 and rate RD-2 was contingent upon the Department's approval of the Company's request to mitigate the distribution rate increase through a decrease in the transition charge. However, as set forth above, the Department has rejected the Company's proposal. Consequently, the Company must modify the method used to set the volumetric rates for rate RD-1 and rate RD-2. The Department directs the Company to design the inclining-block rates for rate RD-1 and rate RD-2 in the same manner in which the Company designed the rates for other rate classes with inclining-block rates. That is, the Company shall set the tail block rate at five percent above the average energy charge for the rate class and recover the remaining revenues through the head block rate. The Department finds that the Company's proposal to set the volumetric charge block break at 600 kWh for rate RD-1 and rate RD-2 is reasonable, as it approximates the average monthly consumption for the customers in this rate class (see Exh. Unitil-PMN-1E at 40).

Regarding the customer charges for rate RD-1 and rate RD-2, the Company proposed to maintain the customer charge of $5.29. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining the current RD-1 customer charge of $5.29 for rates RD-1 and RD-2 strikes the proper balance of economic efficiency and promotion of end-use efficiency. All remaining revenues shall be recovered through the volumetric per kWh charge for these rate classes.

Currently, the Company provides rate RD-2 customers a 24.8-percent discount off of the entire bill. M.D.P.U. No. 192. As discussed below in Section XII.I, the Department has directed Fitchburg to provide its gas division low income customers with a 25-percent discount off of the entire bill. After weighing the benefits to low income residential customers and the change in costs to non-low income customers of increasing the electric low income discount to 25 percent, the Department finds that the overall bill impacts demonstrate a significant benefit to low income customers as compared to a modest increase in the bill impacts on non-low income customers. In addition, the Department notes that implementing a 25-percent discount will simplify the Company’s rates as both gas and electric low income customers will receive the same discount. Accordingly, the Department directs Fitchburg to provide its electric division low income customers with a 25-percent discount off of the entire bill.

2. Rate GD-1

a. Fitchburg’s Proposal

Rate GD-1 is available to all customers with non-residential loads consistently under four kW and energy consumption less than 850 kWh per month (RR-DPU-67, Att. 1, at 49 (proposed M.D.P.U. No. 200)). The Company proposes to maintain the current monthly customer charge of $8.23 (Exh. Sch. PMN-1E-6, at 3). The Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block break set at 200 kWh (Exh. Sch. PMN-1E-6, at 1, 3). Fitchburg proposes a head block charge of $0.06832 per kWh and a tail block charge of $0.07622 per kWh (Exh. Sch. PMN-1E-6, at 3).

b. Analysis and Findings

The Department finds that the Company's proposed method for establishing the volumetric charges for rate GD-1 is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249; and D.P.U. 07-50-A at 25-28. The Department also finds that the Company's proposal to set the volumetric charge block break at 200 kWh for rate GD-1 is reasonable, as it approximates the average monthly consumption for the customers in this rate class (Exh. Unitil-PMN-1E at 40).

Regarding the customer charge for rate GD-1, the Company proposed to maintain the customer charge of $8.23. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining the current customer charge for rate GD-1 at $8.23 strikes the proper balance of economic efficiency and the promotion of end-use efficiency. All remaining revenues shall be recovered through the volumetric per kWh charge for rate GD-1.

3. Rates GD-2, GD-4 and GD-5

a. Fitchburg's Proposal

Rate GD-2 is available to commercial customers with demands (excluding space heating and water heating loads eligible under rate GD-5) consistently greater than or equal to four kW or energy consumption consistently greater than or equal to 850 kWh per month and generally less than 120,000 kWh per month (RR-DPU-67, Att. 1, at 50 (proposed M.D.P.U. No. 200)). Rate GD-4 is an optional general delivery time-of-use ("TOU") rate (RR-DPU-67, Att. 1, at 51 (proposed M.D.P.U. No. 200)). Rate GD-5 is a water and/or space heating delivery rider rate (RR-DPU-67, Att. 1, at 52 (proposed M.D.P.U. No. 200)).

The Company's rate design method for rates GD-2 and GD-4 was to maintain the existing customer charge and increase the demand charge by 28 percent, which is below the average increase for the class as a whole (Exh. Unitil-PMN-1E at 43). A consequence of increasing the demand charge by less than the average increase is that the Company was able to increase the volumetric charges slightly more than average, which the Company states would be consistent with recent Department policy to increase energy charges to promote energy conservation (Exh. Unitil-PMN-1E at 43).

The Company proposes to maintain the monthly customer charge of $8.23 for rates GD-2 and GD-4 (Exh. Sch. PMN-1E-6, at 3; RR-DPU-67, Att. 1, at 40 (proposed M.D.P.U. No. 197)). For rate GD-2, the Company proposes to increase the energy charge from $0.01552 per kWh to $0.02085 per kWh (Exh. Sch. PMN-1E-6, at 3). In addition, Fitchburg proposes to increase the demand rate for rate GD-2 from $6.46 per kW to $8.27 per kW (Exh. Sch. PMN-1E-6, at 3). For rate GD-4, the Company proposes to increase the on-peak energy charge from $0.00697 per kWh to $0.00994 per kWh and increase the off-peak energy charge from $0.00154 per kWh to $0.00201 per kWh (Exh. Sch. PMN-1E-6, at 3). In addition, Fitchburg proposes to increase the demand charge for rate GD-4 from $2.60 per kW to $3.33 per kW (Exh. Sch. PMN-1E-6, at 3). For rates GD-2 and GD-4, the Company also proposes to increase the transformer ownership credit from $0.12 per kW to $0.16 per kW (Exh. Sch. PMN-1E-6, at 3).

For rate GD-5, which is a rider for rate GD-2, the Company proposes to maintain the current monthly customer charge of zero (Exh. Sch. PMN-1E-6, at 3; RR-DPU-67, Att. 1, at 40 (proposed M.D.P.U. No. 197)). In addition, for rate GD-5, the Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block break set at 2,500 kWh (Exh. Sch. PMN-1E-6, at 1, 3). Fitchburg proposes a head block charge of $0.04703 per kWh and a tail block charge of $0.05500 per kWh (Exh. Sch. PMN-1E-6, at 3; RR-DPU-67, Att. 1, at 40 (proposed M.D.P.U. No. 197)).

b. Analysis and Findings

For rate GD-2 and GD-4, the Department finds that the Company's rate design method is reasonable and complies with Department precedent. See D.P.U. 09-30, at 389; D.P.U. 08-35, at 249; D.P.U. 07-50-A at 25-28. Regarding the customer charges for rate GD-2 and rate GD-4, the Company proposes to maintain the customer charges of $8.23. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining the customer charge for rates GD-2 and GD-4 of $8.23 strikes the proper balance of economic efficiency and the promotion of end-use efficiency. In addition, no party objected to the Company's proposal to increase the transformer ownership credit to $0.16 per kW, and the Department finds that the proposal is reasonable.

With respect to the demand and volumetric charges, for large C&I customers the demand charge can send as effective a price signal as the volumetric charge. Accordingly, the Department finds that the Company has not adequately supported its request to increase the demand charge by a different amount than the average increase for the rate class. Therefore, all remaining revenues shall be recovered through the demand charge and the volumetric per kWh charge for rate GD-2 and rate GD-4 with the same percentage increase for both charges.

For rate GD-5, the Department finds that the Company's proposed method for establishing the volumetric charges is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249; and D.P.U. 07-50-A at 25-28. The Department also finds that the Company's proposal to set the volumetric charge block break at 2,500 kWh for rate GD-5 is reasonable, as it approximates the average monthly consumption for the customers in this rate class (Exh. Unitil-PMN-1E at 40).

Regarding the customer charges for rate GD-5, the Company proposed to maintain the customer charge of zero. Because rate GD-5 is a rider to another rate that is already subject to a monthly customer charge, it is appropriate to set the customer charge for this rate at zero. All remaining revenues should be recovered through the volumetric per kWh charge for rate GD-5.

4. Rate GD-3

a. Fitchburg's Proposal

Rate GD-3 is available to industrial and large commercial customers who have monthly usage greater than or equal to 120,000 kWh (RR-DPU-67, Att. 1, at 50 (proposed

M.D.P.U. No. 200)). Rate GD-3 is a TOU rate for which “on-peak” hours are defined as energy use between the hours of 7:00 a.m. and 10:00 p.m. for all non-holiday weekdays, Monday through Friday; all other hours are considered off-peak (RR-DPU-67, Att. 1, at 51 (proposed M.D.P.U. No. 200)).[261]

The Company’s rate design method for this rate class was to decrease the existing customer charge, and increase the demand charge by 28 percent, which is below the average increase for the class as a whole (Exh. Unitil-PMN-1E at 43). As a result, the Company was able to increase the volumetric charges slightly more than average, which the Company states is consistent with recent Department policy to increase energy charges to promote energy conservation (Exh. Unitil-PMN-1E at 43).

The Company proposes to reduce the current monthly customer charge from $500 to $300 for rate GD-3 (Exh. Sch. PMN-1E-6, at 3; RR-DPU-67, Att. 1, at 40 (proposed M.D.P.U. No. 197)). For rate GD-3, the Company proposes to increase the on-peak energy charge from $0.01058 per kWh to $0.01603 per kWh and increase the off-peak energy charge from $0.00237 per kWh to $0.00310 per kWh (Exh. Sch. PMN-1E-6, at 3). In addition, Fitchburg proposes to increase the demand charge for rate GD-3 from $3.43 per kW to $4.39 per kW (Exh. Sch. PMN-1E-6, at 3).

[261] This definition of on-peak and off-peak hours also applies to customers who elect to take service under rate GD-4 (RR-DPU-67, Att. 1, at 51 (proposed M.D.P.U. No. 200)).

b. Analysis and Findings

The Company proposes to decrease the current customer charge for rate GD-3 from $500 to $300. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that a rate GD-3, designed with a $300 customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. For the demand and volumetric charges, the Department sees no reason to increase the demand charge by a different amount than the average increase for the rate class. For large C&I customers, the demand charge can send as effective a price signal as the volumetric charge. Therefore, as part of the Company's compliance filing, all remaining revenues should be recovered through the demand charge and the volumetric per kWh charge for rate GD-3 with a similar increase for both charges.

As noted above, with respect to the demand and volumetric charges, for large C&I customers the demand charge can send as effective a price signal as the volumetric charge. Accordingly, the Department finds that the Company has not adequately supported its request to increase the demand charge by a different amount than the average increase for the rate class. Therefore, all remaining revenues shall be recovered through the demand charge and the volumetric per kWh charge for rate GD-3 with the same percentage increase for both charges.

The Department has concerns with respect to Fitchburg's definition of on-peak and off-peak hours for its TOU rates. Currently, for non-holiday weekdays, peak hours make up 15 hours of each day (7:00 a.m. through 10:00 p.m.). An analysis of the hour during which the system peak occurred in each month from 2005 through 2010 demonstrates that the monthly system peak has only occurred between 11:00 a.m. and 9:00 p.m. (Exh. DPU-1; RR-DPU-9, Att. 1). Consequently, the Department finds that these hours should be modified further. Such a modification will allow those customers who opt for TOU rates to have a reasonable opportunity to reduce costs by shifting load to "off peak" hours.[262] A change of this magnitude will require an analysis of TOU customer billing data and will likely result in changes to test year billing determinants for rate design purposes; therefore, we will not require the Company to make such a change here. As part of its next electric distribution rate case, the Department directs Fitchburg to conduct an analysis of the Company's monthly system peaks to determine if a modification to its off-peak hours for its TOU rates is warranted.

5. Rate SD

a. Fitchburg Proposal

Rate SD is available to all customers for outdoor lighting delivery service with the Company's standard lighting fixtures mounted on existing poles (RR-DPU-67, Att. 1, at 56 (proposed M.D.P.U. No. 201)). The Company states that under its current rates, fixture charges produce approximately 99.5 percent of the revenue for rate SD (Exh. Unitil-PMN-1E at 43). The Company proposes to eliminate the energy charge of $0.00057 per kWh and shift these revenues to be recovered through the fixture charges (Exhs. Unitil-PMN-1E at 43;

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[262] The Department notes that WMECo recently reduced its 16-hour on-peak period for its TOU rates down to eight hours. D.P.U. 10-70, at 295, 326.

Sch. PMN-1E-6, at 6). Fitchburg proposes to increase the fixed rate components for each fixture charge by an equal percentage (31.07 percent) based on the class targeted revenue requirement (Exhs. Unitil-PMN-1E at 43-44; Sch. PMN-1E-6, at 6).

b. Analysis and Findings

Given that the energy charge produces less than one percent of the revenue for rate SD, the Department finds that it is reasonable to eliminate this charge and transfer the recovery of these revenues to the fixture rates. In addition, the Department finds that the Company's proposal to increase all fixture rates by an equal percentage based on the class target revenue requirement is reasonable.

H. Electric Tariff Modifications

1. Metal Halide Outdoor Lighting Option

a. Fitchburg's Proposal

The Company proposes a metal halide outdoor lighting option to replace mercury vapor lights (Exh. Unitil-PMN-1E at 45). Mercury vapor lamps are currently offered by Fitchburg as a "white" light source for street and customer lighting (Exh. Unitil-PMN-1E at 45). However, as of January 1, 2008, in accordance with the Energy Policy Act of 2005,[263] mercury vapor lamp ballasts are no longer manufactured or imported for sale in the United States (Exh. Unitil-PMN-1E at 45). The Company's proposal is intended to provide an alternative lighting source for: (1) existing customers when their mercury vapor ballast fails;

[263] Public Law, 109-58 (August 8, 2005).

(2) customers requesting conversion; and (3) new customers or new lighting installations (Exh. Unitil-PMN-1E at 45). The rates for metal halide lights are based on the estimated plant costs, associated loading costs related to the material and installation costs, and an appropriate levelized fixed charge rate for these fixtures (Exh. Unitil-PMN-1E at 45; RR-DPU-67, Att. 1, at 41 (proposed M.D.P.U. No. 197)).

b. Analysis and Findings

Fitchburg proposes to offer an alternative to those customers who prefer the white light produced by mercury vapor lights. Because mercury vapor lights are no longer available in the United States and metal halide lights produce comparable quality light, we find that the Company's proposal is appropriate. The Department has reviewed the rates proposed by Fitchburg for the range of metal halide streetlight options and finds them to be reasonable (RR-DPU-67, Att. 1, at 41 (proposed M.D.P.U. No. 197)). Accordingly, the Department approves the rates for metal halide outdoor lighting service proposed by Fitchburg and the corresponding modifications to Fitchburg's Rate SD tariff (RR-DPU-67, Att. 1, at 41, 58 (proposed M.D.P.U. Nos. 197, 201)).

I. Gas Rate Design

1. Introduction

The Company based its allocation of revenues to each rate class on several considerations (Exh. Unitil-PMN-1G at 40-41). First, the Company attempted to reflect the results of the COSS as closely as possible by setting rate class revenue requirements at the Company's equalized rate of return (Exh. Unitil-PMN-1G at 40). Second, the Company considered rate continuity to temper rate class or individual customer bill impacts where an equalized rate of return would result in unacceptably large bill impacts, particularly as they relate to any individual rate class versus other rate classes (Exh. Unitil-PMN-1G at 41). Finally, the Company considered Department precedent when setting certain rates, such as proposing inclining block rates for all but the large commercial rate classes (Exh. Unitil-PMN-1G at 44).

The Company proposes to increase the distribution component of bills by 33.69 percent, its equalized rate of return (Exhs. Unitil-PMN-1G at 41; Sch. PMN-1G-8, at 2). The Company examined the increase or decrease in base distribution revenues necessary to produce the allocated cost of service at Fitchburg's equalized rate of return for each rate class (Exh. Unitil-PMN-1G at 41). For those rate classes for which the equalized rate of return is substantially below the Company average rate of return, the Company proposes a distribution rate increase cap equal to 1.25 times the 33.69 percent average, or 42.12 percent (Exh. Unitil-PMN-1G at 41). Based on the Company's proposal, the following rate classes would receive the maximum distribution rate increase: rate R-1, rate R-2, rate R-3, rate R-4, rate G-41 and rate G-51 (Exhs. Unitil-PMN-1G at 41; Sch. PMN-1G-8, at 2). The revenue deficiency that resulted from capping the increase for these rate classes was allocated to the remaining uncapped rate classes based on test year base revenues (Exh. Unitil-PMN-1G at 41).

The Company proposes to decrease the customer charges for Rate G-43 and Rate G-53; the customer charges for all other rate classes would remain unchanged (Exhs. Unitil-PMN-1G at 42; Sch. PMN-1G-8, at 3). Customer charges are discussed further below in the individual rate class section.

In addition, the Company proposes to implement inclining block rates for all rate classes except rates G-43 and G-53 (Exh. Unitil-PMN-1G at 44). The Company stated that it established the size of the rate blocks by reviewing the percentage of non-zero bills during the test year for each non-demand based rate class and choosing a block break where 30 to 40 percent of the non-zero bills occurred (Exh. Unitil-PMN-1G at 44). When designing the inclining block rates, the Company set the tail block at five percent above the average volumetric charge for each rate class (Exh. Unitil-PMN-1G at 43). The head block was then set to recover the residual revenue requirement for each rate class (Exh. Unitil-PMN-1G at 42). For rates R-1 and R-2 (residential non-heating), the Company set the block break at 10 therms (Exh. Unitil-PMN-1G at 44). For rates R-3 and R-4 (residential heating), the Company set the block break at 20 therms (Exh. Unitil-PMN-1G at 44). For rates G-41 and G-51 (small C&I), the Company set the block break at 40 therms (Exh. Unitil-PMN-1G at 44). For rates G-42 and G-52 (medium C&I), the Company set the block break at 500 therms (Exh. Unitil-PMN-1G at 44).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed gas rate design is inconsistent with the Department's rate design principles (Attorney General Brief at 173). Specifically, the Attorney General contends that the proposed rate design will result in unreasonable bill impacts on some rate classes, will not result in intra-class equity, and will not be an effective means of incenting efficient behavior (Attorney General Brief at 173).

First, the Attorney General avers that the Company's proposed rate cap does not fully consider bill impacts, especially because customers will incur an increase to distribution rates as well as an increase to supply rates as recovery of certain costs is being shifted from distribution rates to the cost of gas adjustment ("CGA") (Attorney General Brief at 174). The Attorney General argues that the Company should have set the distribution rate cap at 110 percent of the average distribution increase, rather than the 125 percent proposed by the Company (Attorney General Brief at 174). The Attorney General also argues that a lower distribution rate cap will help address the fact that the increase to the CGA will have a greater impact on higher use customers (Attorney General Brief at 174).

With regard to gas rate design, the Attorney General takes issue with the customer charges, the block break for the inclining block rates and the differential between the head block and tail block rates for the inclining block rates (Attorney General Brief at 175-176). The Attorney General argues that, even though the Company has used a rate setting method similar to the method used for other recent rate cases, the rates that result from Fitchburg's calculations are punitive to higher use customers (Attorney General Brief at 176). In addition, the Attorney General contends that the Company's proposed gas rate design results in large differences in bill impacts within rate classes (Attorney General Brief at 177).

In order to address these issues, the Attorney General recommends a rate design that includes increasing the customer charges for some rate classes[264] and increasing the block break for the residential heating rate classes from 20 therms to 50 therms (Attorney General Brief at 178). Further, the Attorney General asserts that, when designing the inclining-block rates, the tail block rates should be set such that the increase to larger use customers is no more than ten percent greater than the increase to average use customers on the rate (Attorney General Brief at 178). According to the Attorney General, adoption of her alternative gas rate design proposal would result in rates that are more consistent with rate continuity, create more effective price signals, and be more equitable (Attorney General Brief at 179).

b. Low Income Network

The Low Income Network argues that Fitchburg's low income discount applicable to rate R-2 and rate R-4 should be raised to 25 percent (Low Income Network Brief at 2). In support of its argument, the Low Income Network notes that the Department previously raised National Grid's gas division's low income discount to 25 percent (Low Income Network Brief at 1, citing Low Income Discounts, D.P.U. 10-48, at 17 (2010)). The Low Income Network claims that the reason the Department increased National Grid's gas low income discount also apply here, namely: (1) to simplify the low income discount, (2) to reduce customer

[264] The Attorney General proposes a customer charge of $9.50 for the residential rate classes and $26 for rates G-41 and G-51 (Attorney General Brief at 177, citing Exh. AG-LS-1, at 14-15 (gas)).

confusion;[265] and (3) to provide ease in the Department's administration of the discount (Low Income Network Brief at 1, citing D.P.U. 10-48, at 17).

Further, the Low Income Network argues that raising the low income discount to 25 percent would result in substantial benefits to low income customers while having minimal impacts on non low income customers (Low Income Network Brief at 2, citing RR-LI-1, Att. 2 (rev.); Low Income Network Reply Brief at 1). In particular, the Low Income Network claims that an increase in the discount would reduce the burden of energy costs for low income customers in Fitchburg, a community heavily distressed as a result of the recession (Low Income Network Brief at 2; Low Income Network Reply Brief at 1).

c. DOER

DOER asserts that the method used by the Company to determine the breakpoints for its inclining-block rates is consistent with Department precedent and, therefore, DOER recommends that the Department approve the Company's proposed rate design (DOER Brief at 6-7 (gas)). DOER also argues that the Department should reject the Attorney General's proposed alternative rate design (DOER Brief at 7 (gas)). In this regard, DOER contends that the Attorney General has not presented any new evidence that would warrant a departure from Department's inclining-block rates precedent (DOER Brief at 7 (gas)).

[265] The Low Income Network claims that most low income Fitchburg gas customers are also customers of National Grid's electric division and, therefore, receive a 25-percent discount on their electric bills (Low Income Network Brief at 2). Accordingly, the Low Income Network argues that it will reduce customer confusion if these customers also receive a 25 percent discount on their gas bills (Low Income Network Brief at 1-2).

d. Fitchburg

The Company does not object to the Low Income Network's proposed increase to the low income discount (Company Reply Brief at 56).

3. Analysis and Findings

As discussed above, the Department must determine, on a rate class by rate class basis, the proper level to set the customer charge and delivery charge for each rate class, based on our various rate design goals. The rate-by-rate analyses are discussed below. The Department's long standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 194. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance its goals of fairness and continuity. To do this, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes.

The Attorney General argues that the Company's proposed 125 percent rate cap is not appropriate because it results in excessive rate increases for some ratepayers. Instead, the Attorney General recommends a rate cap of 110 percent. Fitchburg's proposal moves closer towards cost-based rates for every rate class. D.P.U. 10-55, at 538; D.T.E. 03-40, at 368. Based on our review of the bill impacts, we find that a 125 percent cap does not violate the Department's continuity goal (Exh. Sch. PMN-1G-9). Further, we conclude that a rate cap of 125 percent is appropriate in these circumstances: (1) to balance our rate structure goals of fairness and continuity by ensuring that the final rates for each rate class represent or approach the cost to serve that class; (2) because the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies; and (3) because the magnitude of change to any one class is contained within reasonable bounds. See D.P.U. 10-55, at 559. Accordingly, we accept the Company's proposed rate design whereby no rate class will receive a distribution rate increase greater than 125 percent of the overall distribution rate increase.

The remaining revenue increase (i.e., the amount above the 125 percent cap) shall be allocated first to those rate classes that would, at equalized rates of return, receive a rate decrease, but only up to the amount that would eliminate such rate decrease. The allocation shall be based on the ratio of each class's decrease to the total decrease for these classes. Any remaining revenue increase shall be recovered on a pro rata basis based on test year base revenues, from those classes whose revenue requirement falls below the 125 percent rate cap and that, at equalized rates of return, would not receive a rate decrease.

Fitchburg has proposed inclining block rates for all but two rate classes (rate G-43 and rate G-53). The Department has directed all natural gas and electric distribution companies to design distribution rates using an inclining block structure. See D.P.U. 08-35, at 249. In D.P.U. 08-35, at 249, the Department found 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, the Department has found that rates should have an inclining block rate structure and any resulting loss in revenues from declining sales should be recovered through a decoupling mechanism. D.P.U. 08-35, at 249.

The Department finds that Fitchburg's proposed inclining block rate structure will promote the efficient use of society's resources and lower customers bills through increased end use efficiency, and is consistent with the Department's directives in D.P.U. 08-35, at 249, and D.P.U. 07-50-A at 25-28. Further, we find that the following elements of Fitchburg's rate design proposal are consistent with our goal to promote end use efficiency: (1) setting the head block sizes for each rate class at a level at which approximately 30 to 40 percent of non-zero bills fall in the head block; (2) setting the tail block rates for each season at 105 percent of the average variable rates for each rate class; and (3) setting the head block rates at a level that would recover the remaining target revenues to be collected through the variable energy charges for each rate class (Exh. Unitil-PMN-1G at 42-44). Therefore, the Department approves the Company's proposed method for establishing the size of the head blocks, the tail blocks, and the respective head block and tail block rates.

While the Department approves the usage levels for the block breaks proposed by the Company in this proceeding, we are concerned that at these usage levels the price signal they will provide for customers to reduce consumption will not be optimized. Consequently, we put all distribution companies on notice that in future rate cases we will require an analysis that demonstrates that the usage level for the block breaks is at an amount that will optimize the price signal for customers to reduce their consumption.

To determine the appropriate customer charges the Department must balance the competing goals of: (1) lowering customers' bills through increased end use efficiency; and (2) rate continuity. The Department finds that Fitchburg's proposal to maintain the customer charges for most rate classes at their current levels provides the appropriate balance of these goals (Exh. Unitil-PMN-1G at 42). The specific rate-by-rate analyses are discussed in the following section.

Regarding the Low Income Network's proposal to increase the gas low income discount to 25 percent, the Department must fully consider and weigh both the benefits to low income residential customers and the change in costs to non low income customers. The Department has reviewed the effects of increasing the low income discount to 25 percent and has determined that the overall bill impacts demonstrate a significant benefit to low income customers as compared to a modest increase in the bill impacts of non low income customers (Exh. LI-1-3, Atts. 1, 2 (gas)). In addition, the Department notes that implementing a 25 percent discount will result in administrative efficiencies as the Company will provide a 25 percent discount to customers of both its gas and electric divisions. Accordingly, the Department directs Fitchburg to increase its low income discount for its gas division to 25 percent.

J. Gas Rate-by-Rate Analysis

1. Rates R-1 and R-3

a. Fitchburg's Proposal

Rate R-1 is available for all domestic purposes in individual private dwellings and in individual apartments other than those for which Rate R-3 applies (RR-DPU-67, Att. 3, at 83 (proposed M.D.P.U. No. 151)). Rate R-3 is available for all domestic purposes in individual private dwellings and in individual apartments where such residences are heated exclusively by means of permanently installed space heating equipment (RR-DPU-67, Att. 3, at 89 (proposed M.D.P.U. No. 153)). Rates R-1 and R-3 are both available only to residential customers taking service in master-metered buildings containing no more than four apartment units with gas supplied through one meter (RR-DPU-67, Att. 3, at 83, 89 (proposed M.D.P.U. Nos. 151, 153)). Fitchburg proposes to maintain the current customer charge of $8.50 for rates R-1 and R-3 (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 83, 89 (proposed M.D.P.U. Nos. 151, 153)). The Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block break set at ten therms for rate R-1 and 20 therms for rate R-3 (Exh. Sch. PMN-1G-8, at 1, 3). For rate R-1, Fitchburg proposes a head block charge of $0.8829 per therm and a tail block charge of $1.0058 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 83 (proposed M.D.P.U. No. 151)). For rate R-3, Fitchburg proposes a head block charge of $0.6149 per therm and a tail block charge of $0.7639 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 89 (proposed M.D.P.U. No. 153)).

b. Analysis and Findings

The Department finds that the Company's proposed method for establishing the volumetric charges for rate R-1 and rate R-3 is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249, and D.P.U. 07-50-A at 25-28. Further, the Department finds that the Company's proposal to set the volumetric charge block break at ten therms for rate R-1 is reasonable, as it approximates the average monthly consumption for customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3). In addition, the Department finds that the Company's proposal to set the volumetric charge block break at 20 therms for rate R-3 is reasonable as it approximates the average monthly consumption for the customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3).

Regarding the customer charges for rates R-1 and R-3, the Company has proposed to maintain the customer charge of $8.50. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining a customer charge of $8.50 for rates R-1 and R-3 strikes the proper balance of economic efficiency and the promotion of end-use efficiency. All remaining revenues shall be recovered through the volumetric per therm charge for rates R-1 and R-3.

2. Rates R-2 and R-4

a. Fitchburg's Proposal

Subsidized rates are available for all domestic purposes in individual private dwellings or individual apartments (RR-DPU-67, Att. 3, at 86, 92 (proposed M.D.P.U Nos. 152, 154)). Eligibility for this rate is established upon verification of a 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 Massachusetts median income based on a household's gross income, or other criteria approved by the Department (RR-DPU-67, Att. 3, at 86, 92 (proposed M.D.P.U. Nos. 152, 154)). Customers who qualify for this subsidy are required each year to certify their continuing eligibility (RR-DPU-67, Att. 3, at 86, 92 (proposed M.D.P.U. Nos. 152, 154)).

Beginning February 1, 2011 the Company modified the application of the low income discount pursuant to Fitchburg Gas and Electric Light Company, D.P.U. 10-41 (2010). Consequently, rates for R-2 were reset so that they are the same as rate R-1. Customers on rate R-2 currently receive a 19.8 percent discount off of their entire bill. M.D. P. U. No. 148. In addition, rates for R-4 were reset so that they are the same as rate R-3. Customers on rate R-4 currently receive a 16.5 percent discount off of their entire bill M.D.P.U. No. 149.

b. Analysis and Findings

The Department finds that the Company's proposed method for establishing the volumetric charges for rate R-2 and R-4 is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249, and D.P.U. 07-50-A at 25-28. Further, the Department finds that the Company's proposal to set the volumetric charge block break at ten therms for rate R-2 is reasonable, as it approximates the average monthly consumption for the customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3). In addition, the Department finds that the Company's proposal to set the volumetric charge block break at 20 therms for rate R-4 is reasonable, as it approximates the average monthly consumption for the customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3).

Regarding the customer charges for rates R-2 and R-4, the Company proposes to maintain the customer charge of $8.50. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining a customer charge of $8.50 for rates R-2 and R-4 strikes a proper balance between economic efficiency and the promotion of end-use efficiency. All remaining revenues shall be recovered through the volumetric per therm charge for rates R-2 and R-4.

3. Rates G-41 and G-51

a. Fitchburg's Proposal

Rates G-41 and G-51 are available to C&I and institutional customers with annual usage of less than 8,000 therms for all purposes when gas is for their exclusive use and not for resale[266] (RR-DPU-67, Att. 3, at 95 (proposed M.D.P.U. No. 155)). The Company proposes to maintain the current customer charge of $24.00 for rates G-41 and G-51 (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 95 (proposed M.D.P.U. No. 155)). The

[266] Rate G-41 is one of the Company's low load factor rate classes (rates G-42 and G-43 are its other low load factor rate classes) (RR-DPU-67, Att. 3, at 95-106 (proposed M.D.P.U. Nos. 155, 156, 157)). Low load factor is defined as those rate classes whose winter usage (i.e., consumption in the months November through April) is greater than or equal to 70 percent of annual usage. Rate G-51 is one of the Company's high load factor rate classes (rates G-52 and G-53 are its other high load factor rate classes) (RR-DPU-67, Att. 3, at 95-106 (proposed M.D.P.U. Nos. 155, 156, 157)). High load factor is defined as those rate classes whose winter usage is less than 70 percent of annual usage.

Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block breaks set at 40 therms for rates G-41 and G-51 (Exh. Sch. PMN-1G-8, at 1, 3). For rate G-41, Fitchburg proposes a head block charge of $0.4766 per therm and a tail block charge of $0.7266 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 95 (proposed M.D.P.U. No. 155)). For rate G-51, Fitchburg proposes a head block charge of $0.4263 per therm and a tail block charge of $0.6190 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 95 (proposed M.D.P.U. No. 155)).

b. Analysis and Findings

The Department finds that the Company's proposed method for establishing the volumetric charges for rate G-41 and rate G-51 is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249, and D.P.U. 07-50-A at 25-28. Further, the Department finds that the Company's proposal to set the volumetric charge block breaks at 40 therms for rates G-41 and G-51 is reasonable, as it approximates the average monthly consumption for customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3).

Regarding the customer charges for rates G-41 and G-51, the Company proposes to maintain the customer charge of $24.00. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining a customer charge of $24.00 for rates G-41 and G-51 strikes a proper balance between economic efficiency and the promotion of end-use efficiency. All remaining revenues should be recovered through the volumetric per therm charge for rates G-41 and G-51.

4. Rates G-42 and G-52

a. Fitchburg's Proposal

Rates G-42 and G-52 are available to C&I and institutional customers with annual usage between 8,000 and 80,000 therms for all purposes when gas is for their exclusive use and not for resale (RR-DPU-67, Att. 3, at 99 (proposed M.D.P.U. No. 156)). The Company proposes to maintain the current customer charge of $120.00 for rates G-42 and G-52 (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 99 (proposed M.D.P.U. No. 156)). The Company proposes to collect the remaining class revenue requirement through inclining block volumetric charges with the block breaks set at 500 therms for rates G-42 and G-52 (Exh. Sch. PMN-1G-8, at 1, 3). For rate G-42, Fitchburg proposes a head block charge of $0.4031 per therm and a tail block charge of $0.5095 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 99 (proposed M.D.P.U. No. 156)). For rate G-52, Fitchburg proposes a head block charge of $0.4194 per therm and a tail block charge of $0.4745 per therm (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 99 (proposed M.D.P.U. No. 156)).

b. Analysis and Findings

The Department finds that the Company's proposed method for establishing the volumetric charges for rate G-42 and G-52 is reasonable and complies with the Department's directives in D.P.U. 09-30, at 389; D.P.U. 08-35, at 249, and D.P.U. 07-50-A at 25-28. Further, the Department finds that the Company's proposal to set the volumetric charge block breaks at 500 therms for rates G-42 and G-52 is reasonable, as it approximates the average monthly consumption for customers in this rate class (Exh. Sch. PMN-1G-8, at 1, 3).

Regarding the customer charges for rate G-42 and rate G-52, the Company proposed to maintain the current customer charge of $120.00. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that maintaining a customer charge of $120.00 for rates G-42 and G-52 strikes a proper balance between economic efficiency and the promotion of end-use efficiency. All remaining revenues shall be recovered through the volumetric per therm charge for rates G-42 and G-52.

5. Rates G-43 and G-53

a. Fitchburg’s Proposal

Rates G-43 and G-53 are available to C&I and institutional customers with annual usage greater than 80,000 therms for all purposes when gas is for their exclusive use and not for resale (RR-DPU-67, Att. 3, at 103 (proposed M.D.P.U. No. 157)). The Company designed rates for rates G-43 and G-53 by first reducing the customer charge based on cost of service results (Exh. Unitil-PMN-1G at 43). The demand charge for each rate was then increased by the overall class percentage increase (Exhs. Unitil-PMN-1G at 43; Sch. PMN-1G-8, at 2, 4). Finally, the volumetric charge for each rate was calculated to recover the remaining revenue requirement (Exh. Unitil-PMN-1G at 43).

The Company proposes to decrease the monthly customer charge from $620.00 to $500.00 for rates G-43 and G-53 (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 103 (proposed M.D.P.U. No. 157)). The current volumetric charges for rates G-43 and G-53 are $0.2262 per therm and $0.2079 per therm, respectively (Exh. Sch. PMN-1G-8, at 3). The current demand charges for rates G-43 and G-53 are $1.38 per maximum daily demand ("MDD") therm and $1.74 per MDD therm, respectively (Exh. Sch. PMN-1G-8, at 3). The proposed volumetric charge and demand charge for rate G-43 are $0.2624 per therm and $1.50 per MDD therm, respectively (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 103 (proposed M.D.P.U. No. 157)). The proposed volumetric charge and demand charge for rate G-53 are $0.2280 per therm and $1.85 per MDD therm, respectively (Exh. Sch. PMN-1G-8, at 3; RR-DPU-67, Att. 3, at 103 (proposed M.D.P.U. No. 157)).

b. Analysis and Findings

Regarding the customer charge for rates G-43 and G-53, the Company proposed to decrease the current customer charge from $620.00 to $500.00. As stated above, the Department must balance economic efficiency with price signals that promote end-use efficiency. The Department finds that rates G-43 and G-53, designed with a $500.00 customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. All remaining revenues shall be recovered through the demand charge and the volumetric per therm charge for rates G-43 and G-53 consistent with the rate design method described above.

K. Distribution Service Terms and Conditions Tariff

The Company has not proposed any changes to its Distribution Service Terms and Conditions tariff, M.D.T.E. No. 121 (RR-DPU-67, Att. 4, at 3-82 (proposed M.D.T.E. No. 121)). However, the tariff includes many outdated references to the

Department of Telecommunications and Energy.[267] Therefore, the Department directs the Company, as part of its compliance filing to this Order, to update this tariff by: (1) assigning it a M.D.P.U. number; (2) changing all references to the "Department of Telecommunications and Energy" to "Department of Public Utilities"; and (3) changing all references to "MDTE" to "MDPU."

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[267] Pursuant to the 1997 Restructuring Act, the Department's name was changed from "Department of Public Utilities" to "Department of Telecommunications and Energy." "An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Customer Protection Therein," St. 1997, c. 164. Pursuant to the 2007 "Governor's Reorganization Plan", the Department's name was changed from "Department of Telecommunications and Energy" to "Department of Public Utilities." St. 2007, c. 19.

XIII. SCHEDULES

A. Schedule 1 (Electric Division) – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	9,075,870	(104,840)	(2,133,801)	6,837,229
Depreciation & Amortization	4,874,341	33,569	(405,839)	4,502,071
Taxes Other Than Income Taxes	1,088,087	338,054	0	1,426,141
Income Taxes	1,934,581	(288,604)	(234,005)	1,411,972
Return on Rate Base	4,934,624	(81,643)	(386,266)	4,466,714
Proposed Storm Recovery Adjustment	2,205,868	(12,281)	(564,403)	1,629,184
Total Cost of Service	24,113,371	(115,745)	(3,724,315)	20,273,311
OPERATING REVENUES				
Total Base Distribution Revenues	16,765,447	0	0	16,765,447
Other Operating Revenues	198,295	0	33,698	231,993
Total Operating Revenues	16,963,742	0	33,698	16,997,440
Total Revenue Deficiency	**7,149,629**	**(115,745)**	**(3,758,012)**	**3,275,871**

B. Schedule 2 (Electric Division) – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense per Books	53,035,143	0	0	53,035,143
Less:				
Energy Efficiency	1,510,048	0	0	1,510,048
External Transmission	5,012,690	0	0	5,012,690
Transition Charge	10,767,483	0	0	10,767,483
Pension/PBOP Adjustment Factor	765,035	0	0	765,035
Rental Water Heaters	17,760	0	20,628	38,388
Basic Service	24,145,909	0	0	24,145,909
Residential Assistance Adjustment Factor	88,072	0	0	88,072
Test Year Distribution O&M Expense	10,728,146	0	(20,628)	10,707,518
ADJUSTMENTS TO O&M EXPENSE:				
Payroll	156,765	0	(122,598)	34,167
Medical & Dental Insurance	48,982	(19,553)	(39,908)	(10,479)
Property & Liability Insurance	36,839	7,926	0	44,765
401(k) Costs	35,278	0	4,037	39,315
Bad Debt	30,955	(559)	(72,660)	(42,264)
Inflation Allowance	92,385	0	(27,601)	64,784
Management Audit Expenses	(905,639)	0	0	(905,639)
2008 Ice Storm Investigation Adjustment	(789,708)	0	(394,854)	(1,184,562)
Non-Test Year Audit Fees	16,175	0	0	16,175
Tree Trimming (Vegetation Management Plan)	1,359,509	(50,000)	(1,309,509)	0
Storm Reserve	200,000	0	(200,000)	0
Non-Distribution Bad Debt	(26,960)	0	0	(26,960)
Sales for Resale	(1,018,657)	0	0	(1,018,657)
Other Expenses	(5,609)	(45,793)	0	(51,402)
Shareholder Services	0	0	(27,051)	(27,051)
Rate Case Expense	0	0	207,967	207,967
D.P.U. 09-09 Consulting Costs	0	0	(118,536)	(118,536)
Employee Reimbursments / Expenses	0	0	(12,460)	(12,460)
Total O&M Expense Adjustments	(769,685)	(107,979)	(2,113,173)	(2,990,837)
Total O&M Expense	**9,958,461**	**(107,979)**	**(2,133,801)**	**7,716,681**
Less: Internal Transmission	882,591	(3,139)	0	879,452
Total Distribution O&M Expense	**9,075,870**	**(104,840)**	**(2,133,801)**	**6,837,229**

C. Schedule 3 (Electric Division) – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Depreciation Expense	4,752,769	0	(8,324)	4,744,445
Test Year Amortization Expense	1,275,332	0	(172,917)	1,102,415
Subtotal	6,028,101	0	(181,241)	5,846,860
Less: Transition Charge	819,569	0	0	819,569
Total Test Year Depreciation & Amortization	5,208,532	0	(181,241)	5,027,291
Depreciation Adjustment	(41,518)	(21,191)	0	(62,709)
Amortization Adjustment	0	0	(58,703)	(58,703)
Active Hardship Protected Accounts	0	86,109	(86,109)	0
Rate Case Expense Amortization	111,135	(31,349)	(79,786)	0
Subtotal	5,278,149	33,569	(405,839)	4,905,879
Less: Internal Transmission	382,169	0	0	382,169
Less: Water Heater Rentals	21,639	0	0	21,639
Total Distribution Depreciation & Amortization Expenses	**4,874,341**	**33,569**	**(405,839)**	**4,502,071**

D. Schedule 4 (Electric Division) – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	106,081,985	(104,126)	0	105,977,859
Less: Internal Transmission	9,591,342	(9,825)	0	9,581,517
Subtotal	96,490,643	(94,301)	0	96,396,342
Depreciation Reserve	37,093,793	655,446	0	37,749,239
Less: Internal Transmission	4,014,065	61,849	0	4,075,914
Subtotal	33,079,728	593,597	0	33,673,325
Net Utility Plant in Service	63,410,915	(687,898)	0	62,723,017
ADDITIONS TO PLANT:				
ISO Deposit	1,114,759	(1,114,759)	0	0
Cash Working Capital	878,832	21,041	(234,758)	665,115
Materials and Supplies	952,850	0	0	952,850
Less: Materials and Supplies Internal Transmission	82,250	0	0	82,250
Total Additions to Plant	2,864,191	(1,093,718)	(234,758)	1,535,715
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	9,196,712	(830,067)*	0	8,366,645
Unclaimed Funds	767	0	0	767
Customer Deposits	257,699	0	0	257,699
Customer Advances	136,900	0	0	136,900
Less: Deferred Taxes Internal Transmission	830,068	0	0	830,068
Total Deductions from Plant	8,762,010	(830,067)	0	7,931,943
RATE BASE	57,513,096	(951,549)	(234,758)	56,326,789
COST OF CAPITAL	8.58%	8.58%	7.93%	7.93%
RETURN ON RATE BASE	**4,934,624**	**(81,643)**	**(386,266)**	**4,466,714**

* This total was omitted from the Company's DPU-3-11 Supp. 3.

E. Schedule 5 (Electric Division) – Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	10.70%	4.59%
Total Capital	$125,680,372	100.00%		8.58%
Weighted Cost of				
Debt				3.89%
Equity				4.69%
Cost of Capital				8.58%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	10.70% *	4.59%
Total Capital	$125,680,372	100.00%		8.58%
Weighted Cost of				
Debt				3.89%
Equity				4.69%
Cost of Capital				8.58%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	9.20%	3.94%
Total Capital	$125,680,372	100.00%		7.93%
Weighted Cost of				
Debt				3.89%
Equity				4.04%
Cost of Capital				7.93%

* On Brief, the Company agreed to 10.5 percent

F. Schedule 6 (Electric Division) – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total Distribution O&M Expense	9,075,870	(104,840)	(2,133,801)	6,837,229
Less: Uncollectibles	531,115	2,580	0	533,695
Taxes Other than Income Taxes	1,088,087	338,054	0	1,426,141
Proforma Working Capital	9,632,842	230,634	(2,133,801)	7,729,675
Lead-Lag Days	33.30	33.30	31.41	31.41
CWC Factor (Lead-Lag Days/365)	9.1233%	9.1233%	8.6047%	8.6047%
CWC Allowance	**878,832**	**21,041**	**(234,758)**	**665,115**

G. Schedule 7 (Electric Division) – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes per Books	970,369	242,776 *	0	1,213,145
Less: Taxes Capitalized	10,224	0	0	10,224
Less: Internal Transmission	86,660	21,912	0	108,572
Total Property Taxes	873,485	220,864	0	1,094,349
FICA Taxes	183,572	0	0	183,572
Federal Unemployment Taxes	1,857	0	0	1,857
Mass Unemployment Taxes	9,552	0	0	9,552
Mass Universal Health	0	0	0	0
Less: Payroll Taxes Capitalized	82,753	0	0	82,753
Less: Internal Transmission	10,590	0	0	10,590
Other Distribution Taxes	112,964	117,190	0	230,154
Total Taxes Other Than Income Taxes	**1,088,087**	**338,054**	**0**	**1,426,141**

* This total was omitted from the Company's DPU-3-11 Supp. 3.

H. Schedule 8 (Electric Division) – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	57,513,096	(951,549)	(234,758)	56,326,789
Return on Rate Base	4,934,624	(81,643)	(386,266)	4,466,714
LESS:				
Interest Expense	2,237,259	(37,015)	(9,132)	2,191,112
Total Deductions	2,237,259	(37,015)	(9,132)	2,191,112
Taxable Income Base	2,697,364	(44,628)	(377,134)	2,275,602
Gross Up Factor	1.6204829	1.6204829	1.6204829	1.6204829
Taxable Income	4,371,033	(72,318)	(611,140)	3,687,575
Mass Franchise Tax	284,117	(4,701)	(39,724)	239,692
6.50%				
Federal Taxable Income	4,086,916	(67,617)	(571,416)	3,447,883
Federal Income Tax Calculated	1,389,551	(22,990)	(194,281)	1,172,280
Total Income Taxes Calculated	1,673,668	(27,691)	(234,005)	1,411,972
FAS 109 Annual Revenue Requirement	260,913	(260,913)	0	0
Total Income Taxes	**1,934,581**	**(288,604)**	**(234,005)**	**1,411,972**

I. Schedule 9 (Electric Division) – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	61,786,987	0	0	61,786,987
Less:				
Pension/PBOP Adjustment Factor	939,186	0	0	939,186
External Transmission	5,033,585	0	0	5,033,585
Transition Charge	11,257,300	0	0	11,257,300
Default Service	24,243,572	0	0	24,243,572
Energy Efficiency	834,236	0	0	834,236
RAAF	1,244,606	0	0	1,244,606
Internal Transmission	1,339,011	0	0	1,339,011
Base Distribution Revenue Adjustment	130,044	0	0	130,044
Total Revenue Adjustments	45,021,540	0	0	45,021,540
Total Distribution Base Revenues	16,765,447	0	0	16,765,447
Other Operating Revenues	1,639,488	0	33,698	1,673,186
Less: Transition Charge	197,303	0	0	197,303
Less: Energy Efficiency	777,424	0	0	777,424
Less: Water Heater Rental	56,566	0	0	56,566
Less: Internal Transmission	409,900	0	0	409,900
Total Other Operating Revenues	198,295	0	33,698	231,993
Adjusted Total Operating Revenues	**16,963,742**	**0**	**33,698**	**16,997,440**

J. Schedule 10 (Electric Division)

For illustrative purposes only

Department Approved Distribution Revenue Increase $ 3,275,871

RATE CLASS	Per Cost of Service Study: Proposed COSS Target Revenue at EROR (1)	Current Revenue (2)	Proposed Deficiency at EROR (3)	Percent Increase at EROR (4)	Proposed Increase at Total Company % Increase (5)	Department Approved Revenue at EROR (6)	% Increase @Department Approved Revenue at EROR (7)	Department Approved Revenue Target (8)
RD-1/RD-2	$12,164,779	$ 9,062,899	$3,101,880	34.23%	$11,834,846	$2,055,390	22.68%	$10,899,667
GD-1	$ 562,071	$ 437,903	$ 124,168	28.36%	$ 571,838	$ 82,277	18.79%	$ 526,652
GD-2	$ 5,096,747	$ 4,098,095	$ 998,652	24.37%	$ 5,351,524	$ 661,734	16.15%	$ 4,928,651
GD-3	$ 2,611,204	$ 2,157,594	$ 453,611	21.02%	$ 2,817,508	$ 300,575	13.93%	$ 2,594,871
GD-4	$ 5,267	$ 4,235	$ 1,032	24.37%	$ 5,530	$ 684	16.15%	$ 5,093
GD-5	$ 27,629	$ 22,215	$ 5,414	24.37%	$ 29,010	$ 3,587	16.15%	$ 26,717
SD	$ 639,725	$ 380,720	$ 259,004	68.03%	$ 497,166	$ 171,623	45.08%	$ 457,880
Total	$21,107,421	$16,163,661	$4,943,761	30.59%	$21,107,422	$3,275,871	20.27%	$19,439,532

Source:
(1) Schedule PMN-1E-6, at 2, Column (N).
(2) Schedule PMN-1E-6, at 2, Column (L).
(3) Schedule PMN-1E-6, at 2, Column (O).
(4) Column (3) / Column (2)
(5) Column (2) * (1+ Column (4) “Total”). Schedule PMN-1E-6, at 2, Column (X).
(6) (Department Approved Distribution Revenue Increase/Column (3) Total) * Column (3) for each rate class
(7) Column(6)/Column(2)
(8) Column(2) * (1 + Column (7) “Total”)

FOR ILLUSTRATIVE PURPOSES ONLY

K. Schedule 1 (Gas Division) – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	6,950,010	(73,975)	(213,404)	6,662,631
Depreciation & Amoritzation	3,556,107	293,641	(233,134)	3,616,614
Taxes Other Than Income Taxes	993,791	260,103	0	1,253,894
Income Taxes	1,644,287	(165,317)	(207,395)	1,271,575
Return on Rate Base	4,407,086	(46,508)	(338,005)	4,022,574
Special Contracts	0	0	(75,055)	(75,055)
Total Cost of Service	17,551,282	267,944	(1,066,993)	16,752,233
OPERATING REVENUES				
Operating Revenues	10,185,312	0	0	10,185,312
Revenue Adjustments	2,918,441	0	(75,055)	2,843,386
Total Operating Revenues	13,103,753	0	(75,055)	13,028,698
Total Revenue Deficiency	**4,447,529**	**267,944**	**(991,938)**	**3,723,535**

L. Schedule 2 (Gas Division) – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	32,211,921	0	0	32,211,921
Less:				
Pension/PBOP Adjustment Factor	774,959	0	0	774,959
Residential Assistance Adjustment Factor	96,064	0	0	96,064
Energy Conservation Surcharge	348,926	0	0	348,926
Other LDAC	866,750	0	0	866,750
Total LDAC	2,086,699	0	0	2,086,699
Less:				
CGA	18,532,179	0	0	18,532,179
Rental Water Heaters	90,773	0	149,018	239,791
Subtotal	18,622,952	0	149,018	18,771,970
Test Year Distribution O&M Expense	11,502,270	0	(149,018)	11,353,252
ADJUSTMENTS TO O&M EXPENSE:				
Payroll	182,097	0	(82,758)	99,339
Medical and Dental Insurance	24,237	(26,871)	(29,036)	(31,670)
Property and Liability Insurance	25,826	(56,373)	0	(30,547)
Bad Debt	4,459	23,731	(67,754)	(39,564)
401(k) Costs	25,791	0	(2,767)	23,024
Inflation Allowance	76,753	0	(9,419)	67,334
Gas Refund Adjustment to CGA	(4,954,787)	0	0	(4,954,787)
Non-Test Year Audit Fees	12,056	0	0	12,056
Other Expense Removal	(4,456)	(14,462)	0	(18,918)
Non-Distribution Bad Debt	55,764	0	0	55,764
Shareholder Services	0	0	(18,262)	(18,262)
Rate Case Expense	0	0	154,021	154,021
Employee Reimbursements / Expenses	0	0	(8,411)	(8,411)
Total O&M Expense Adjustments	(4,552,260)	(73,975)	(64,386)	(4,690,621)
Total Distribution O&M Expense	**6,950,010**	**(73,975)**	**(213,404)**	**6,662,631**

M. Schedule 3 (Gas Division) – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Depreciation Expense	3,857,144	0	0	3,857,144
Test Year Amortization Expense	397,692	0	(154,021)	243,671
Test Year Depreciation and Amortization Expense	4,254,836	0	(154,021)	4,100,815
Depreciation Adjustment	(264,512)	230,275	0	(34,237)
Amortization Adjustment	0	0	(54,228)	(54,228)
Active Hardship Protected Accounts	0	72,101	(72,101)	0
Rate Case Expense Amortization	(38,481)	(8,735)	47,216	0
Subtotal	3,951,843	293,641	(233,134)	4,012,350
Less: Water Heater Rentals	395,736	0	0	395,736
Total Distribution Depreciation and Amortization Expense	**3,556,107**	**293,641**	**(233,134)**	**3,616,614**

N. Schedule 4 (Gas Division) – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	80,446,345	104,126	0	80,550,471
LESS:				
Depreciation and Amortization Reserve	26,433,984	667,514	0	27,101,498
Net Utility Plant in Service	54,012,361	(563,388)	0	53,448,973
ADDITIONS TO PLANT:				
Cash Working Capital	977,783	21,339	(96,567)	902,555
Materials and Supplies	361,343	0	0	361,343
Total Additions to Plant	1,339,126	21,339	(96,567)	1,263,898
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	3,825,668	0	0	3,825,668
Unclaimed Funds	606	0	0	606
Customer Deposits	139,039	0	0	139,039
Customer Advances	21,532	0	0	21,532
Total Deductions from Plant	3,986,845	0	0	3,986,845
RATE BASE	51,364,642	(542,049)	(96,567)	50,726,026
COST OF CAPITAL	8.58%	8.58%	7.93%	7.93%
RETURN ON RATE BASE	**4,407,086**	**(46,508)**	**(338,005)**	**4,022,574**

O. Schedule 5 (Gas Division) – Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	10.70%	4.59%
Total Capital	$125,680,372	100.00%		8.58%
Weighted Cost of				
Debt				3.89%
Equity				4.69%
Cost of Capital				8.58%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	10.70% *	4.59%
Total Capital	$125,680,372	100.00%		8.58%
Weighted Cost of				
Debt				3.89%
Equity				4.69%
Cost of Capital				8.58%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$ 70,000,000	55.70%	6.99%	3.89%
Preferred Stock	$ 1,789,300	1.42%	6.74%	0.10%
Common Equity	$ 53,891,072	42.88%	9.20%	3.94%
Total Capital	$125,680,372	100.00%		7.93%
Weighted Cost of				
Debt				3.89%
Equity				4.04%
Cost of Capital				7.93%

* On Brief, the Company agreed to 10.5 percent

P. Schedule 6 (Gas Division) – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total Distribution O&M Expense	6,950,010	(73,975)	(213,404)	6,662,631
Less: Uncollectibles	502,372	23,731	0	526,103
Subtotal	6,447,638	(97,706)	(213,404)	6,136,529
Taxes Other Than Income Taxes	993,791	260,103	0	1,253,894
Amount Subject to Cash Working Capital	7,441,429	162,397	(213,404)	7,390,423
Lead-Lag Days	47.96	47.96	44.58	44.58
CWC Factor (Lead-Lag Days / 365)	13.1397%	13.1397%	12.2125%	12.2125%
Total Cash Working Capital Allowance	**977,783**	**21,339**	**(96,567)**	**902,555**

Q. Schedule 7 (Gas Division) – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes per Books	778,989	160,359*	0	939,348
Less: Capitalized Property Taxes	8,208	0	0	8,208
Subtotal	770,781	160,359	0	931,140
FICA Taxes	189,087	0	0	189,087
Federal Unemployment	1,914	0	0	1,914
State Unemployment	9,839	0	0	9,839
Capitalized Payroll Taxes	(51,270)	0	0	(51,270)
Adjustment to Distribution Other Taxes	73,440	99,744	0	173,184
Total Taxes Other Than Income Taxes	**993,791**	**260,103**	**0**	**1,253,894**

* This total was omitted from the Company's DPU-2-11 Supp. 3.

R. Schedule 8 (Gas Division) – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	51,364,642	(542,049)	(96,567)	50,726,026
Return on Rate Base	4,407,086	(46,508)	(338,005)	4,022,574
LESS:				
Interest Expense	1,998,085	(21,086)	(3,756)	1,973,242
Total Deductions	1,998,085	(21,086)	(3,756)	1,973,242
Taxable Income Base	2,409,002	(25,422)	(334,248)	2,049,331
Gross Up Factor	1.6205	1.6205	1.6205	1.6205
Taxable Income	3,903,746	(41,196)	(541,643)	3,320,907
Mass Franchise Tax	253,743	(2,678)	(35,207)	215,859
6.50%				
Federal Taxable Income	3,650,003	(38,518)	(506,436)	3,105,048
Federal Income Tax Calculated	1,241,001	(13,096)	(172,188)	1,055,716
Total Income Taxes Calculated	1,494,744	(15,774)	(207,395)	1,271,575
FAS 109 Annual Revenue Requirement	149,543	(149,543)	0	0
Total Income Taxes	**1,644,287**	**(165,317)**	**(207,395)**	**1,271,575**

S. Schedule 9 (Gas Division) – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	30,709,050	0	0	30,709,050
Less:				
Pension/PBOP Adjustment Factor	715,336	0	0	715,336
LDAC	636,842	0	0	636,842
CGA	18,703,159	0	0	18,703,159
Energy Conservation Surcharge	293,427	0	0	293,427
Residential Assistance Adjustment Factor	638,273	0	0	638,273
Total Revenue Adjustments	20,987,037	0	0	20,987,037
Distribution Base Revenues	9,722,013	0	0	9,722,013
Weather Normalization	(56,406)	0	0	(56,406)
Low Income Discount Recovery	717,742	0	0	717,742
EEC Lost Revenue	(59,088)	0	0	(59,088)
Unbilled Revenue	(194,713)	0	0	(194,713)
Non-Distribution Bad Debt	55,764	0	0	55,764
Total Distribution Base Revenues	10,185,312	0	0	10,185,312
Other Operating Revenues	4,059,549	0	0	4,059,549
Less: Pension/PBOP Adjustment Factor	236,265	0	0	236,265
Less: LDAC	167,331	0	0	167,331
Less: CGA	59,134	0	0	59,134
Less: Energy Conservation Surcharge	66,697	0	0	66,697
Less: Residential Assistance Adjustment Factor	175,532	0	0	175,532
Less: Special Contracts	0	0	75,055	75,055
Less: Water Heater Rental	436,149	0	0	436,149
Other Operating Revenues Per Books	2,918,441	0	(75,055)	2,843,386
Adjusted Total Operating Revenues	**13,103,753**	**0**	**(75,055)**	**13,028,698**

T. Schedule 10 (Gas Division)

For illustrative purposes only

Line No.	TOTAL COMPANY per Order	DISTRIBUTION SERVICE	GAS SERVICE	TOTAL COMPANY as filed	As Filed DISTRIBUTION SERVICE per Company	As Filed GAS SERVICE per Company
1 Cost of Gas	(6,950,010)	—	(6,950,010)	(6,950,010)	—	(6,950,010)
2 O&M Expense	6,662,636	5,605,567	1,057,069	6,950,010	5,847,347	1,102,663
3 Operations Expenses	(287,374)	5,605,567	(5,892,941)	22,662,486	5,847,347	(5,847,347)
4 Depreciation Expense	3,210,243	3,100,899	109,344	3,196,896	3,088,006	108,890
5 Amortization Expense	406,371	353,945	52,426	359,211	312,869	46,342
6 Taxes Other Than Income Taxes	1,253,894	1,153,759	100,135	993,791	914,427	79,364
7 Income Taxes	1,271,575	1,197,427	74,148	1,644,287	1,548,406	95,881
8 Interest on Customer Deposits	—	—	—	—	—	—
9 Amortization of ITC	—	—	—	—	—	—
10 Rate Base	50,726,027	47,756,419	2,969,608	51,364,642	48,357,648	3,006,994
11 Rate of Return	7.93%	7.93%	7.93%	8.58%	8.58%	8.58%
12 Return on Rate Base	4,022,574	3,787,084	235,490	4,407,086	4,149,086	258,000
13 Cost of Service	9,877,283	15,198,680	(5,321,397)	33,263,758	15,860,142	(5,258,870)
14 Revenues Credited to Cost of Service	(799,752)	(704,430)	(95,321)	(799,752)	(704,430)	(95,321)
15 **Total Cost of Service**	**9,077,531**	**14,494,250**	**(5,416,718)**	**32,464,006**	**15,155,711**	**(5,354,192)**
16 Operating Revenues - per books	34,768,599	14,950,106	19,818,493	34,768,599	14,950,106	19,818,493
17 Revenues Transferred to Cost of Service	(799,752)	(704,430)	(95,321)	(799,752)	(704,430)	(95,321)
18 Revenue Adjustments	(5,952,372)	(2,909,508)	(3,042,864)	(5,952,372)	(2,909,508)	(3,042,864)
19 **Total Operating Revenues**	**28,016,475**	**11,336,167**	**16,680,308**	**28,016,475**	**11,336,167**	**16,680,308**
20 Revenue Deficiency	**3,723,540**	**3,197,780**	**525,760**	**4,447,531**	**3,819,544**	**(22,034,500)**

THIS SCHEDULE IS FOR ILLUSTRATIVE PURPOSES ONLY.

U. Schedule 11 (Gas Division)

Department-approved Distribution Revenue Increase $3,197,780

RATE CLASS	AS FILED TEST YEAR BASE REVENUES (1)	AS FILED TEST YEAR TOTAL REVENUES (2)	PROPOSED TARGET REVENUE INCREASE AT EROR (3)	PROPOSED % INCREASE AT EROR (4)	CLASS INCREASE (5)	PROPOSED TARGET REVENUE (6)	PER ORDER TARGET BASE REVENUE INCREASE AT EROR (7)	PER ORDER % INCREASE AT EROR (8)	PER ORDER CLASS INCREASE AT 125% CAP (9)	PER ORDER REVENUE TO BE RE-ALLOCATED (10)	PERCENT ALLOCATION OF RE-ALLOCATED REVENUES TO NON-CAPPED RATE CLASSES (11)	PER ORDER RE-ALLOCATED REVENUE (12)	PER ORDER CLASS INCREASE (13)	PER ORDER PROPOSED TARGET REVENUE (14)
R-1/R-2	$ 682,289	$ 1,447,236	$ 827,882	121.34%	$ 287,358	$ 969,647	$ 693,115	101.59%	$ 240,581	$452,535			$ 240,581	$ 922,870
R-3/R-4	$ 5,393,153	$16,649,497	$ 2,581,038	47.86%	$ 2,271,422	$ 7,664,575	$ 2,160,885	40.07%	$ 1,901,670	$259,215			$ 1,901,670	$ 7,294,823
G-41 Small General, High Winter Use	$ 1,196,962	$ 3,489,244	$ 601,668	50.27%	$ 504,122	$ 1,701,084	$ 503,726	42.08%	$ 422,059	$ 81,668			$ 422,059	$ 1,619,021
G-51 Small General, Low Winter Use	$ 333,316	$ 965,439	$ 175,400	52.62%	$ 140,382	$ 473,698	$ 146,847	44.06%	$ 117,530	$ 29,317			$ 117,530	$ 450,846
G-42 Medium General, High Winter Use	$ 1,646,145	$ 4,511,373	($ 21,053)	-1.28%	$ 412,588	$ 2,058,733	($ 17,626)	-1.07%	-$ 17,626	$ 0	44.13%	$363,050	$ 345,425	$ 1,991,570
G-52 Medium General, Low Winter Use	$ 383,348	$ 1,135,685	($ 21,875)	-5.71%	$ 79,110	$ 462,458	($ 18,314)	-4.78%	-$ 18,314	$ 0	10.28%	$ 84,546	$ 66,232	$ 449,580
G-43 Large General, High Winter Use	$ 732,639	$ 2,020,554	($ 129,658)	-17.70%	$ 63,339	$ 795,978	($ 108,552)	-14.82%	-$ 108,552	$ 0	19.64%	$161,581	$ 53,028	$ 785,667
G-53 Large General, Low Winter Use	$ 968,316	$ 1,536,303	($ 193,859)	-20.02%	$ 61,222	$ 1,029,538	($ 162,302)	-16.76%	-$ 162,302	$ 0	25.96%	$213,558	$ 51,256	$ 1,019,572
Total	$11,336,168	$31,755,331	$ 3,819,543	33.69%	$ 3,819,543	$15,155,711	$ 3,197,780	28.21%	$ 2,375,045	$822,735	100%	$822,735	$ 3,197,780	$14,533,948
		Overall Rate Increase * 1.25		42.12%				35.26%						

Sources:

(1) Schedule PMN-1G-8, Page 2, Column (O)
(2) Column (1) + Column (2) + Column (3)
(3) Schedule PMN-1G-8, Page 2, Column (R)
(4) Column (5 / Column (1)
(5) Column (7) + Column (10)
(6) Column (1) + Column (11)
(7) (Department-approved Distribution Revenue Increase/Column (5) Toatl) * Column (5) for each rate class
(8) Column (13)/Column(1)
(9) If Column (14) > 125% cap % then Column (1) * (1+ 125% cap %) - Column (1), otherwise Column (13)
(10) Column(13) - Column (15)
(11) Test Year Base Revenues for Individual Non-capped Rate Classes/Total Test Year Base Reveneus for Non-capped Rate Classes
(12) Column (17) for each non-capped rate class * Column (16) Total
(13) Column (15) + Column (18)
(14) Column (1) + Column (19)

THIS SCHEDULE IS FOR ILLUSTRATIVE PURPOSES ONLY

XIV. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 195 through 205, filed by Fitchburg Gas and Electric Light Company, d/b/a Unitil on January 14, 2011, to become effective on February 1, 2011, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 151 through 161 and M.D.P.U. No. 133, filed by Fitchburg Gas and Electric Light Company, d/b/a Unitil on January 14, 2011, to become effective on February 1, 2011, are DISALLOWED; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company, d/b/a Unitil shall file new schedules of rates and charges designed to increase annual electric base rate revenues by $3,275,871; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company, d/b/a Unitil shall file new schedules of rates and charges designed to increase annual gas base rate revenues by $3,723,535; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company, d/b/a Unitil 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 Fitchburg Gas and Electric Light Company, d/b/a Unitil shall comply with all other orders and directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to all electricity and gas consumed on or after the date of this Order, 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/
Jolette A. Westbrook, Commissioner

/s/
David W. Cash, 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.