COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

REBUTTAL TESTIMONY OF

MARK NEWTON LOWRY

D.P.U. 13-90

SUBMITTED ON BEHALF OF

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

d/b/a UNITIL

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 22 E. Mifflin Street, Suite 302, Madison, WI 53703.

Q. What is your position and what are your responsibilities?

A. I am the President of Pacific Economics Group ("PEG") Research LLC. My responsibilities as President include the management of the company, consultation on alternative regulation ("Altreg"), supervision of utility industry statistical research, and expert witness testimony. I am testifying in this proceeding on behalf of Fitchburg Gas & Electric Company ("FG&E" or the "Company").

Q. Have you previously filed testimony in these proceedings?

A. Yes. My direct testimony was submitted on July 15, 2013. I have also responded to numerous data requests from the Attorney General ("AG") and Department of Public Utilities ("D.P.U." or "the Department") on that testimony.

II. OVERVIEW OF FILING

Q. What is the purpose of your testimony?

A. I will discuss certain revisions and clarifications to the Company's two Altreg proposals in this proceeding and rebut certain statements about these proposals and the need for supplemental revenue that are made in the direct testimony of the Attorney General's witness David Dismukes.

III. CAPITAL COST ADJUSTMENT MECHANISM

Q. Please begin by discussing any revisions and clarifications to the Company's CCAM proposal.

A. Based upon the testimony of Dr. Dismukes, the Company has determined that a number of clarifications are in order.

- First, the CCAM as initially proposed *would* allow for the recovery of costs of special Grid Modernization and reliability-related capital expenditures ("capex"), in addition to conventional capex. This feature is necessary because the Department's recent deliberations on this topic may lead to substantial, new capex requirements. The ratemaking treatment of special capex would differ, however. Special capex would require pre-approval by the Department – a condition the Attorney General has repeatedly recommended in the Grid Modernization docket. A cap on conventional capex would be established in this proceeding. A cap on special Grid Modernization and reliability capex would not, but could be established at a later date.
- Second, in developing its CCAM proposal, FG&E did not consider the alternative of combining the rate impact limits for decoupling and the CCAM. Upon further reflection, the Company does not object to limiting the combined annual decoupling/CCAM revenue impact to 3% in order to make the CCAM more consistent with the mechanism approved by the Department for Massachusetts Electric in D.P.U. 09-39. Also, consistent with the Department's findings in D.P.U. 09-39, the portion of the adjustment that exceeds the 3% cap would be

deferred for recovery until the next year with carrying charges at the customer deposit rate.

- Third, the Company believes that setting the cap on conventional capex based on its *projected* capital budget is reasonable, but would not object to establishing the cap based on a three-year *historical average*. Consistent with the D.P.U. 09-39 order, the cap should be based on the Company's *total* distribution capex. The Dismukes proposal to use a limited portion of capex is inconsistent with that order and relies heavily on Department precedents for gas distributors which have a different context.

Q. What areas of Dr. Dismukes' testimony concerning the CCAM do you wish to rebut?

A. My testimony will refute the following assertions of Dr. Dismukes:

- The CCAM is somehow not needed because the Company does not need high capex.
- The proposed CCAM proposal differs from prior capital cost tracker precedents in Massachusetts.
- Regulators in other states have rejected some capital cost tracker proposals.

Q. Please comment on Dr. Dismukes' assertions that the Company does not need the CCAM "because its distribution system is not old and in need of replacement" and its reliability is not poor.

A. First, there is, in fact, a real risk that the Company will be compelled by the Department to undertake special reliability capex in the next few years. While the proposed CCAM can address this financing challenge, more importantly it is reasonable even in the absence of a substantial reliability improvement program or any other special need for high capex. I explained in my direct testimony that the CCAM was designed as part of an Altreg plan, in conjunction with decoupling, to avoid frequent rate cases over a repetitive set of issues. In response to concern about the lack of supplemental revenue from sales growth under decoupling, the Department in D.P.U. 07-50-A authorized supplemental revenue between rate cases for inflation, capex, and customer growth. A broad-based capital cost tracker is a means of providing supplemental revenue in a manner that is consistent with Department precedent. Moreover, the avoidance of frequent rate cases is especially desirable for a small utility like FG&E. Finally, the CCAM or some other enhancement to FG&E's revenue adjustment mechanism ("RAM") will help the Company to maintain its service quality over the long term.

FG&E follows a rigorous and appropriate maintenance and capital replacement program for its distribution system, as Dr. Dismukes' data suggests, and its reliability record is respectable. It would be poor public policy for the Department to approve broad-based capital cost trackers only for electric utilities that have neglected replacement capex. If the Company had a remarkably old system and/or bad service quality, Dr. Dismukes might well complain that it was undeserving of a tracker. As he concedes in his response to information request FGE-AGO 1-17, he, in fact, used grounds like these for opposing a capital cost tracker for Potomac Electric Power Company ("Pepco") in a 2012 proceeding in Maryland.[1]

[1] Direct Testimony of David E. Dismukes on Behalf of the Maryland Office of People's Counsel, Case 9286, March 2012, pp. 13-18.

Q. On page 6 of his testimony, Dr. Dismukes recommends that the Company be required to provide a showing that its investments are "additional and incremental to those included in base rates." Is this a necessary or appropriate change?

A. No. The Company's change in net plant value approach to establishing the CCAM revenue requirement ensures that there is compensation only for investments that are additional and incremental to those in base rates.

Q. Please respond to Dr. Dismukes' assertions on page 17 of his testimony that the Company's proposed CCAM differs from the one approved in D.P.U. 09-39 for Massachusetts Electric in "a number of important ways."

A. The Company's CCAM proposal, as revised and clarified, is consistent in all material aspects with the capital cost tracker approved in D.P.U. 09-39.

- The plan features a capital cost tracker that is broad-based in the sense that it compensates the utility for increases in the total cost of capital.
- The Company is willing to limit the annual capex eligible for tracking to the average for three recent historical years. In the next rate case, the test year cost of any capex exceeding this cap may be considered for inclusion in the revenue requirement.
- Only capex from the prior year is eligible for addition to the CCAM revenue requirement.
- Annual growth in revenue resulting from the combined operation of the revenue decoupling and capital cost tracker is limited to 3%. Any surplus would be recovered in subsequent years with interest at the customer deposit rate.
- There is a safeguard against double counting of capital cost.

- The chance of excessive compensation from the Altreg plan is further reduced by the fact that no escalation is provided in the budget for O&M expenses in order address the cost impact of inflation or customer growth.

Q. Dr. Dismukes claims that the D.P.U. approved the Massachusetts Electric proposal because it was "unrelated to customer growth." Yet on page 56 of his Direct Testimony he makes the related claim that the broad-based character of the CCAM is "clearly outside the spirit of the Department's ruling in D.P.U. 07-50-A, which limited capital cost recovery in conjunction with revenue decoupling to pressing safety and reliability needs and excluded normal course of business investments." What is your response to these statements?

A. In identifying a need for supplemental revenue under decoupling, the Department did not state in D.P.U. 07-50-A that the need for reliability capex must be "pressing," or that inflation and customer growth must be remarkably rapid. As for the distinction between customer-related capex and other capex, I believe that this becomes meaningful only when allowed revenue is escalated automatically for customer growth. In that context, it makes sense to exclude growth-related capex from tracker eligibility so as to avoid double counting. Escalation of revenue for customer growth was assumed in D.P.U. 07-50-A but never approved for FG&E or Massachusetts Electric.

I would also note that growth-related capex clearly *is* covered by the plan approved for Massachusetts Electric, even though the customer growth of Massachusetts Electric was close to zero in 2008 (but has since rebounded and modestly exceeds that of FG&E in a typical year).

Q. Are there precedents for broad-based capital cost trackers in other states?

A. Yes. Broad-based trackers for power distribution capital cost are permissible in several jurisdictions, and are operational for several utilities in Ohio.

Q. Do you have any concerns with respect to Dr. Dismukes' discussions of the rejections of capital cost trackers proposed by other utilities?

A. Yes. Regulatory decisions from other jurisdictions in which capital cost trackers were rejected must be carefully examined for relevance. For example, rejected tracker proposals may have been poorly supported, offered fewer customer protections, been inconsistent with local ratemaking traditions, or been less necessary due to other revenue growth opportunities.

Q. Dr. Dismukes references the rejection of capital cost trackers for Pepco and Peoples Gas Light and Coke as examples where the utility failed to support the cost-effectiveness of the proposal. How do you respond?

A. The Company is not at this time proposing a massive construction program like these utilities (and Massachusetts Electric) proposed. Elaborate demonstrations of need are not necessary for conventional capex when it is capped at a level similar to recent historical expenditures. In the event that special Grid Modernization capex is mandated, the Company will welcome the opportunity to file additional evidence of need.

Q. On page 16 of his testimony Dr. Dismukes highlights the narrower scope of capital cost trackers for gas distributors in the Commonwealth. What is your response to his statements?

A. The capital cost trackers for Commonwealth *gas* utilities do have a more limited scope, but these utilities also have RAMs that escalate revenue automatically for customer growth. The trackers for some gas utilities do not net off depreciation. It is also noteworthy that the gas utilities benefitted particularly from decoupling due to material declines in average use.

Q. Are there other relevant differences between the Company and other utilities that Dr. Dismukes mentions concerning the opportunities for revenue growth between rate cases?

A. Yes. The CCAM is proposed in the context of a decoupling true up plan with a RAM that provides little automatic escalation in revenue between rate cases. It is virtually impossible for a utility to have a reasonable opportunity to earn its rate of return following the conclusion of the rate case (usually a year or more after the test year) with little revenue growth (absent deep cost reductions that may only be available through deterioration of service quality, reliability and safety). In contrast, Rhode Island's commission (Dismukes' footnotes 73/74) denied Narragansett Electric's tracker proposal, but also denied the company's revenue decoupling proposal. Narragansett was thus able to continue benefitting from any growth in its billing determinants. Pepco did have a decoupling true up plan but its RAM escalated revenue automatically for customer growth.

Q. Are there other salient differences between the Company's situation and those of the companies cited by Dismukes?

A. Yes. FG&E already has a service quality penalty mechanism, while Pepco opposed the implementation of such a mechanism in the DC proceeding that Dr. Dismukes cites on page 29 of his testimony. Pepco and other utilities with rejected capital cost tracker proposals requested that tracker budgets be based on forecasts even though the commission did not sanction forward test years in rate cases. In contrast, FG&E requests only rate adjustments for the prior year's capex, in keeping with the Department's rate case tradition. Some commissions (*e.g.* those in Illinois and Rhode Island) resist the tracking of costs that are not large and volatile. The Department has, in contrast, approved several capital cost trackers. Also, the Company has proposed a sunset date for its tracker whereas Pepco did not.

Q. Dr. Dismukes states on page 20 of his testimony that the Company's CCAM proposal is similar to Western Massachusetts Electric's rejected capex proposal, "particularly in their deficiencies." Is this an accurate statement?

A. No. The Company is not at this time proposing a large increase in its capex, so the quality of the evidence on its capex budget is not at issue. Approval of a budget for special Grid Modernization capex would require solid evidence. WMECO had experienced a downward trend in sales for many years. In contrast, our filing stresses that if the sales of FG&E have not recently grown it is because of its large DSM program, high volumetric rates, and the impact of other pro-conservation policies in the Commonwealth. The number of customers is also growing gradually.

Q. Has Dr. Dismukes supported the use of capital cost trackers in other proceedings?

A. Yes. In the DC capital tracker proceeding for Pepco that he mentions, Dr. Dismukes was a witness for the Office of the People's Counsel ("OPC"). The OPC stated the following in response to Pepco Data Request 1-209 in that proceeding:

> Dr. Dismukes prepared the Louisiana Staff recommendation, which was approved by the full Commission, for an environmental cost recovery rider. Dr. Dismukes also prepared the Louisiana Staff recommendation, which was approved by the full Commission, for a nuclear power plant cost recovery rider. Dr. Dismukes also prepared the Louisiana Staff recommendation, approved by the full Commission, for cost recovery for Advanced Metering Infrastructure . . . costs.

IV. NEED FOR SUPPLEMENTAL REVENUE

Q. Let's turn now to the comments Dr. Dismukes makes on the need for supplemental revenue. He states on page 21 of his testimony that "the Company has been able to make significant investments over the last 18 years with only four rate cases." How do you respond?

A. This statement is misleading because he chooses a period long enough to encompass much of the 1990s, a decade when rate relief was rarely needed. All four of the rate cases he mentions have been held since 2000, and the Company is currently in another. In total then, five rate cases have been filed in the past thirteen years. The four concluded cases provided substantial revenue growth for the Company. Unfortunately, the need for rate cases has increased since the implementation of revenue decoupling and large-scale DSM.

Q. Why were rate increases less necessary in the 1990s?

The Company operated then under more favorable business conditions than it has since the turn of the century. The merger with Unitil in 1992 created possibilities for scale and scope economies. A bull market in stocks reduced the need for pension contributions. Bond yields were falling, and utilities found it easier to refinance without sizable concessions to bondholders than they do today. The Company stopped building its own generation capacity, and depreciation of existing capacity slowed growth in the total rate base. This was also a decade in which expanded use of personal computers stimulated productivity growth. Business conditions were so favorable that the Company was drawn into an overearnings investigation that ended with rate reductions.

Q. How do you respond to Dr. Dismukes' statement that the Company has made considerable capital investments in the last ten years despite sales that have been static or declining?

A. This commentary is misleading, due in part to the fact that the start date for the volume trend he notes is *2003*, the year after a rate case. In fact, FG&E's sales during the four years from 2003 to 2006 were well above those on which the rates established in 2002 were based. This helped the Company avoid a rate case for several years. Since 2006, FG&E has continued capex despite a downward sales trend. The 2008 recession and economic troubles in the region have significantly impacted the Company's sales, but the Department recognized in D.P.U. 09-39 that such a short-term view should not be the basis for denying a capital tracker.

It should also be noted that to continue its capex program the Company has recently filed several rate cases and under-earned in several years. The Company's under-earning is the primary driver for the current proceeding. I believe the Altreg plans that I have proposed are preferable to frequent rate cases and related under-earning as a means of managing the Company's capex requirements going forward.

Q. Does the Company have any special circumstances that explain its preference to avoid filing frequent rate cases?

A. Yes. The relatively small size of FG&E makes the Company especially reluctant to file for rate increases since a substantial share of the first-year revenue growth resulting from a rate case would be offset by higher regulatory costs. Please also note the FG&E, like many utilities, was reluctant to file a rate case during the recent recession.

Q. Dr. Dismukes asserts on page 24 of his testimony that "freezing revenues alone through a revenue decoupling mechanism cannot challenge a normal level of investment that is typically included in base rates." Is that correct?

A. No. Depreciation of existing plant does afford a utility a small budget for capex but, since depreciation expenses reflect the construction costs of earlier years and base rates in Massachusetts are based on historical test years, the rates resulting from a rate case cannot typically fund rate base growth unless revenue is supplemented by some means. In the past, growth in billing determinants provided some revenue growth to help fund capex but that source of supplemental revenue is no longer available.

Q. Dr. Dismukes argues on page 47 that inflation has been "relatively tame" and "at rates comparable to overall economy-wide inflation." How do you respond?

A. I did not claim in my direct testimony that the inflation facing Northeast power distributors is especially rapid. Furthermore, rapid inflation is not commonly a requirement for the implementation of PBR, as Dr. Dismukes acknowledges in his response to information request FGE-AGO 1-11. The need for supplemental revenue depends instead on whether inflation materially exceeds productivity growth, and I have shown that this is typically the case for Northeast power distributors. PBR for energy utilities in Massachusetts and many other jurisdictions was adopted in an era of *slow* inflation. Periods of slow inflation are, from a consumer's standpoint, a good time to implement PBR.

Input price inflation has, in any event, not been remarkably slow for energy distributors in the Northeast. This is reflected in the figures Dr. Dismukes provides concerning trends in prices for nonferrous wire and cable, steel mill products, power and distribution transformers, and construction sand/gravel/crushed stone. Prices of these products have experienced unusually rapid inflation in recent years. Even without further rapid inflation, high prices for these products would accelerate growth in the rate base of FG&E because of the disparity between current construction costs and those reflected in the older plant that is still in the rate base.

Q. Dr. Dismukes notes on page 49 the slow growth in the producer price index ("PPI") for residential power distribution in New England. How do you respond?

A. The PPI for power distribution that Dr. Dismukes cites is of no relevance to the issues in this proceeding. The North American Industry Classification System defines the electric power distribution industry as one that "comprises electric power establishments primarily engaged in either (1) operating electric power distribution systems (*i.e.*, consisting of lines, poles, meters, and wiring) or (2) operating as electric power brokers or agents that arrange the sale of electricity via power distribution systems operated by others." The PPIs for power distribution in New England are designed for that industry and reflect prices of power merchant service as well as distribution services. Bulk power prices in New England are sensitive to trends in natural gas prices and the demand for power.

V. REVENUE CAP INDEX

Q. Let's turn now to the Company's proposed PBR plan. Please begin by discussing any revisions to the Company's PBR proposal.

A. Dr. Dismukes notes in his testimony that the term of the Company's proposed PBR plan is shorter than those of several plans that the Company has approved. However, as he acknowledges in his response to information request FGE-AGO-1-7, "Section 18 of Senate Bills No. 2395 signed by Governor Patrick on August 3, 2012, requires electric companies to file rate schedules with the Department no more frequently than every five years." Our survey of PBR plans in North America reveals that the average term of current plans is a little less than five years. FG&E is open to a plan with a five year term, the maximum permissible. The Company has also expressed a willingness to add an earnings sharing mechanism ("ESM") to its plan, but reminds the Department that these mechanisms erode cost containment incentives and the rationale for a positive stretch factor.

Q. Are there any other changes in the Company's proposal?

A. Yes. The Company has proposed the Gross Domestic Product Price Index ("GDPPI") as the inflation measure for its RCI. Since the filing of our testimony in July, the federal government has completed the latest in a series of occasional reviews and revisions of the way that it calculates the GDPPI. An important focus of this revision has been to better capture the role of intellectual property. The revised GDPPI grew a little more slowly over the sample period we used in our index research. This alters the X factor that is indicated by our research by increasing the input price differential. A revised Table 5 presents the results of new X factor calculations that employ the revised GDPPI. It can be seen that the indicated X factor falls modestly, from 0.15% to 0.01%. Please note that, from a customer viewpoint, the effect of the reduced X factor on revenue growth is likely to be mitigated by slower GDPPI growth.

Q. What areas of Dr. Dismukes' testimony on your PBR proposal do wish to rebut?

A. My testimony will refute the following assertions made by Dr. Dismukes:

- That the Company's PBR proposal is a "misnomer" and offers customers no benefits.
- That the proposal is flawed due to the exclusion of certain provisions and supportive evidence.
- That the proposed plan is dissimilar to previous PBR plans approved by the Department.
- That the Department ruled that PBR plans were no longer needed given the existence of revenue decoupling.
- That my productivity research is somehow biased.
- That the proposed productivity offset is lower than in current PBR plans.

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Table 5 (Revised)

X-Factor Calculation

Year	Inflation Differential: U.S GDPPI Growth Original	Inflation Differential: U.S GDPPI Growth Revised[1]	Inflation Differential: U.S MFP Growth	Inflation Differential: U.S Economy Input Price Inflation Original	Inflation Differential: U.S Economy Input Price Inflation Revised[1]	Inflation Differential: Distributor Input Price Inflation	Inflation Differential: Input Price Differential Original	Inflation Differential: Input Price Differential Revised[1]	Productivity Differential: Distributor MFP Growth	Productivity Differential: Productivity Differential	Stretch Factor	X-Factor Original	X-Factor Revised[1]
	[A]	[B]	[C]	[D]=[A]+[C]	[E]=[B]+[C]	[F]	[G]=[D]-[F]	[H]=[E]-[F]	[I]	[J]= [I]-[C]	[K]	[L]= [J]+[G]+[K]	[M]= [J]+[H]+[K]
2002	1.60%	1.53%	2.40%	4.00%	3.93%	2.49%	1.51%	1.44%	2.42%	0.02%	0.20%	1.73%	1.66%
2003	2.08%	1.98%	2.70%	4.78%	4.68%	3.77%	1.01%	0.91%	-0.94%	-3.64%	0.20%	-2.42%	-2.53%
2004	2.78%	2.70%	2.40%	5.18%	5.10%	3.13%	2.05%	1.97%	5.75%	3.35%	0.20%	5.60%	5.52%
2005	3.27%	3.16%	1.00%	4.27%	4.16%	3.89%	0.38%	0.27%	0.47%	-0.53%	0.20%	0.05%	-0.06%
2006	3.19%	3.03%	0.40%	3.59%	3.43%	5.21%	-1.62%	-1.78%	1.80%	1.40%	0.20%	-0.03%	-0.19%
2007	2.86%	2.63%	0.30%	3.16%	2.93%	1.79%	1.37%	1.13%	-0.22%	-0.52%	0.20%	1.05%	0.81%
2008	2.17%	1.90%	-1.20%	0.97%	0.70%	3.92%	-2.94%	-3.21%	-0.12%	1.08%	0.20%	-1.66%	-1.93%
2009	0.89%	0.80%	-0.10%	0.79%	0.70%	3.00%	-2.21%	-2.30%	2.05%	2.15%	0.20%	0.14%	0.05%
2010	1.33%	1.21%	2.50%	3.83%	3.71%	4.19%	-0.36%	-0.48%	-0.27%	-2.77%	0.20%	-2.93%	-3.05%
2011	2.11%	1.95%	0.70%	2.81%	2.65%	3.29%	-0.48%	-0.65%	0.93%	0.23%	0.20%	-0.05%	-0.22%
Average Annual Growth Rate													
2002-2011	**2.23%**	**2.09%**	**1.11%**	**3.34%**	**3.20%**	**3.47%**	**-0.13%**	**-0.27%**	**1.19%**	**0.08%**	**0.20%**	**0.15%**	**0.01%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price and MFP indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), Regulatory Research Associates (electric utility allowed ROE), and US Bureau of Economic Analysis (GDPPI)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Hudson Gas & Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Duquesne Light, Green Mountain Power, Jersey Central Power & Light, Massachusetts Electric, Metropolitan Edison, Narragansett Electric, NSTAR Electric, Orange & Rockland, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, and West Penn Power.

[1] Includes 2013 comprehensive revision to GDP data conducted by the Bureau of Economic Analysis. The revision was applied to 1929-2013 GDP and thus data that are a function of GDP, such as GDPPI. The major aspects of the revision include new measures of intellectual property as well as improved measures to benefit defined pensions. More information is available at: http://www.bea.gov/national/an1.htm

Q. Please respond to Dr. Dismukes' claims that the Company's PBR proposal is a "misnomer" and that "there is nothing ratepayers can expect to gain."

A. These contentions are simply outlandish. The proposed X factor would ensure customers the benefit of productivity growth exceeding the industry trend. The Company would achieve a superior rate of return only by achieving productivity growth that is superior to this trend. *That is the definition of a PBR plan*. Importantly, no utility in Massachusetts currently guarantees customers the benefit of industry productivity growth.

Additional customer benefits flow from the fact that the Company's cost containment incentives will be strengthened because rate cases will be filed less frequently. As a result, management would have more time to devote to its basic business of providing quality services cost effectively. The regulatory community would have more time to devote to other pressing issues that matter to customers. Benefits of long-term performance gains that are achieved during the plan would be passed through to ratepayers in the next rate case.

Q. What about Dr. Dismukes' comment on page 37 about the exclusion of pricing flexibility provisions?

A. Pricing flexibility provisions have been common in approved PBR plans for telecom utilities but have played a much smaller role in plans for energy utilities. This is due in part to concerns about externalities from energy production and consumption, and in part to what have historically been relatively inelastic demands for energy distribution services. The Company, in any event, cannot benefit from pricing flexibility under decoupling.

Q. Dr. Dismukes notes that several PBR plans approved by the Department feature earnings sharing mechanisms that differ from the ESM you discuss in your testimony. Should this be a cause of Department concern?

A. No. While the provisions of ESMs certainly vary across approved PBR plans, the provisions I discuss are still very typical of those approved across the country. The Company can accept these provisions, and would also likely be open to variations on the theme. In any event, when Dr. Dismukes was asked in information request FGE-AGO 1-9 what in his view is the ideal ESM for the Company, he responded that "There is no such thing as an 'ideal ESM' since an ESM is only one component of an overall PBR and cannot be examined in a vacuum." In my opinion, this is a good example of how Dr. Dismukes has attempted to cast a little doubt on many aspects of the Company's two Altreg proposals without offering criticisms that are trenchant.

Q. Dr. Dismukes implies on page 15 of his testimony that an attrition study is an appropriate component of a PBR filing. Is that correct?

A. No. An attrition study considers whether under-earning is a likely outcome of a rate case. Such studies are, in fact, rare in PBR filings. Dr. Dismukes cites attrition relief filing guidelines detailed in a 1985 DC decision. These guidelines pertained to requests for "attrition adjustments," which were occasionally requested by utilities in the early 1980s due, in part, to rapid inflation. The same decision rejected the use of "cost of service indexing," which was rarely used in regulation in that era.[2] Thus, the DC guidelines did not pertain to the filing of PBR plans.

[2] Public Service Commission of the District of Columbia, Order No. 8204, April 1985.

Q. Dr. Dismukes implies that a "supranormal level of infrastructure investment" needs to be proven in order to adopt any form of PBR. Is that correct?

A. No. The need for a "supranormal level of infrastructure investment" is not a common criterion for PBR plan approval. As I noted previously, this has not been a requirement for a PBR plan in Massachusetts under the terms of D.P.U. 07-50-A. Indeed, such a need *complicates* development of a plan because a capex surge cannot then be financed by an attrition relief mechanism based on industry price and productivity trends. The Company may in the next few years be obliged by Department policy to undertake special reliability capex related to Grid Modernization initiatives, and the proposed PBR plan would address this challenge as a Z factor eligible event. However, normal cost growth, which results in part from reliability-related capex, is reason enough to implement PBR for a firm operating under revenue decoupling.

Q. Is Dr. Dismukes' comment that the Company's proposal is "similar to the PBR plans adopted, and later abandoned, by other Massachusetts natural gas utilities" constructive?

A. No. I believe that it is a misleading statement. The Bay State and Boston Gas plans failed because they were *price* cap plans with X factors that were not designed to compensate the utilities for a secular decline in average use, much less the demand impact of the recent recession. The Company is instead proposing a *revenue* cap index ("RCI"). An RCI typically has a term that escalates allowed revenue automatically for growth in operating scale. These are typically output metrics with relatively stable growth patterns such as the number of customers served. As I explain in Section 2.2.2 of AG 5-02 Attachment, the detailed report on my indexing research, the same scale escalator should be used to measure industry productivity growth. Since volatile output metrics are not required in the research, the risk of a poorly designed revenue cap index is smaller than the risk of a poorly-designed price cap index.

Note also that Bay State and Boston Gas had less need for a PBR plan once they were granted capital cost trackers and automatic revenue escalation for customer growth. Further, the capital cost trackers of Bay State have not netted out depreciation expenses.

Q. On page 43 of his testimony, Dr. Dismukes notes the Department's characterization of PBR combined with decoupling as "inconsistent with the objectives and principles of decoupling," and its statement that PBR plans "would no longer be necessary or appropriate". Are these fair characterizations of the Department's decision?

A. No. In D.P.U. 07-50-A the Department expressed a clear willingness to combine decoupling and PBR plans. These plans can provide compensation for inflation, capex, and customer growth and be "similar in structure to the PBR rate plans that most electric and gas companies have in place today." The Department does require that PBR proposals must be "fully supported," and my testimony and responses to data requests have provided extensive support.

Q. Please comment on Dr. Dismukes' appraisal of your productivity research.

A. Dr. Dismukes criticizes my use of a revenue-weighted customer index to measure the trend in the output of Northeast power distributors. He states on page 50 of his testimony that the number of customers served is not the sole determinant of cost and not a "true measure" of the services offered by the Company. He also believes that my customer index "serves as a downward bias on estimated output growth," and, by extension, MFP growth.

Q. Does Dr. Dismukes make a convincing case for downward bias in your productivity research?

A. No. He presents results for alternative output metrics for calculating MFP and shows that the output and MFP trends may be higher or lower when different metrics are used. In other words, the output metric I proposed has a trend *in the middle* of the range for the output metrics that Dr. Dismukes reports.

I should also note that Table 4 of my direct testimony presents results for the *total* number of customers served, as well as for the customer index I featured in my research. It can be seen that the trend for total customers averaged 0.66% annual growth whereas the trend for the customer index averaged 0.75% annual growth. If my goal was downward bias, it would obviously have made sense to use the total number of customers in my productivity calculations.

Q. Were all of the alternative output metrics that Dr. Dismukes reported valid alternatives to your customer index?

A. No. Dr. Dismukes obtains a markedly *higher* productivity trend only using his "excess factor" and "peak demand" variables. These variables are based on a measure of peak demand obtained from the Monthly Peaks and Output section of the FERC Form 1. His research using these variables is problematic in several respects.

- The peak demand variable includes requirement sales for resale. These are not a distribution service, and were appreciable for some sampled companies in some years of the sample period.

- The peak demand trend that he included for NSTAR was not corrected for the merger that occurred during the sample period. The reported peak demand growth for NSTAR was the most rapid in the sample. Removing NSTAR from the sample reduces the average trend in peak demand considerably.
- Peak load data were unavailable for a few companies in my sample. Dr. Dismukes calculated the average peak load trend without data for these companies, but then computed MFP using the average input quantity trend for *all* companies.
- Peak demand measures are unusually sensitive to demand volatility. There is no reason to believe that a particular period of only ten years, such as the 2002-2011 sample period in my study, is appropriate for measuring the long term trend in peak demand in the Northeast, much less a trend tailored to conditions in Massachusetts, where a large DSM program has been underway in the last few years. Peak demand is sensitive to weather and other volatile business conditions. Cooling degree days in the Northeast were appreciably higher in the last year of the sample period (2011) than in the first (2001). This should materially elevate the peak demand trend.

The more valid alternative to customer-based output metrics that Dr. Dismukes advances is the delivery volume. This metric actually grew more *slowly* than my customer index during the sample period. Its use, either alone or in an average with the customer trend, would therefore slow measured productivity growth and raise the X factor.

Q. Did Dr. Dismukes provide any empirical support for the appropriateness of his alternative output metrics?

A. He attempts to do so in Schedule DED-13, where he lists a few studies of electric utility cost and the output variables that were featured in the cost models. Surprisingly, five of the nine studies he cites are for costs of generation, transmission, or vertically integrated electric operations. The number of customers served is, of course, a much less important cost driver in the provision of these services than it is in power distribution. Dr. Dismukes' review of the literature is also highly selective. For example, a study that I published in a respected professional journal was excluded. Dr. Dismukes concludes from his survey on page 51 that "the overwhelming majority of the [models] use sales (MWhs) as some measure of output". Yet sales grew more slowly than my customer index during the sample period!

I have supervised a more careful and thorough review of the scale variables used in econometric studies of power distributor cost. This review focused on studies published in books and journal articles. Seven studies were carefully examined. We found that the number of customers and the volumes delivered and sold were used in some form in all of these studies. Measures of service territory area, line length, peak demand, and load factor (a related variable) were also employed in some studies but were less popular.

Other studies have been reported in regulatory proceedings but not published.[3] A recent and pertinent example is an econometric model of total power distributor cost developed by PEG Research for the Ontario Energy Board using data from more than seventy Ontario utilities. In this study, data were available for (i) distribution peak demand, (ii) delivery volume and (iii) the number of customers served. The estimated elasticities of cost with respect to these three output variables were 0.105%, 0.161%, and 0.444%,

[3] Numerous studies I authored were listed in the Company's response to data request AG 2-3.

respectively.[4] The number of customers was thus found to be the most important of the three cost drivers by far, while peak demand was found to be the least important.[5]

Q. What of Dr. Dismukes statement that the number of customers is not a true measure of the Company's services?

A. I disagree. As I explained in Section 2.2 of the report on my indexing research, the output metrics that are appropriate in productivity research to calibrate X factors for revenue and price cap indexes differ. In rate regulation, rate increases compensate utilities for the gap between cost and billing determinant growth. In designing a price cap index, it then makes sense for the measure of output in the supportive productivity research to reflect the trend in billing determinants. This may be where Dr. Dismukes developed the notion that output should be a "true measure" of services.

A *revenue* cap index, however, should be designed to compensate utilities for external conditions that drive cost growth. Any output measure used in RCI design should therefore be an important cost driver irrespective of whether it is a revenue driver. The number of customers served is, in any event, a bona fide billing determinant for most energy distributors.

Q. Are there other arguments in favor of the output specification in your study?

A. Yes. As I have already mentioned, the output treatment used in productivity measurement should match that used as a scale escalator in the RCI. Delivery volume and peak demand are awkward scale escalators to use in the context of revenue

[4] The elasticity of cost with respect to an output variable is the percentage change in cost resulting from a 1% change in the variable.
[5] PEG Research, "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board," November 2013, p. 58.

decoupling because if revenue grows automatically with system use, an incentive is reintroduced to promote system use.

I should also note that the number of customers does not have to be the *sole* determinant of costs in order to be a good "stand-alone" output metric. Simplicity has its virtues, and the trend in my customer index may be a reasonably good approximation of the trend in a weighted average of several output metrics. Research to establish appropriate weights is expensive and complicated.

Q. Do the actions of regulators support your decision to use customers in the output specification?

A. Yes. The balance of considerations that I just discussed helps to explain why the number of customers has been used to escalate allowed revenue automatically in numerous revenue decoupling plans. Most notably, it is used in the plans for gas utilities in Massachusetts and many other states. The Department, in fact, noted in D.P.U. 07-50-A (p. 38) that in D.P.U. 07-50 “We proposed that each distribution company recover a fixed amount of revenues per customer, for each customer class, which would ensure that revenues are more closely aligned with the number of customers – a significant driver of costs on their distribution systems”.

Q. How do you respond to Dr. Dismukes’ comparison on pages 51-53 and Schedule DED-12 of “base distribution revenue growth” to your calculated inflation-productivity gap?

A. This is not a valid measure of base *distribution* revenue growth because it contains transmission revenue as well. Furthermore, as I explained in my direct testimony, the inflation-productivity gap is intended for comparison to the trend in *average use*, not *base rate revenue.* It is not surprising that revenue growth exceeds the inflation-productivity gap because the utility must also be compensated for growth in its operating scale.

As I explained in my direct testimony, a sensible general formula for an energy distribution revenue cap index is *inflation – productivity + customer growth*. Thus, it is interesting to compare the trend in the base rate revenue data Dr. Dismukes reports to the sum of my inflation/productivity gap and the average trend in my customer index. This comes to 3.03% (2.28% + 0.75%), which is remarkably close to Dr. Dismukes' 3.10% estimated trend in base revenue.

In any event, the revenue growth that Dr. Dismukes reports was aided by rate cases, multiyear rate plans, capital cost trackers, and growth in billing determinants. The problem in Massachusetts is that utilities no longer receive supplemental revenue from growth in billing determinants, and frequent rate cases are an undesirable means of making up the difference.

Q. **Dr. Dismukes notes on page 53 that unit costs have increased by "two-thirds the input price rate". Does this undermine the import of your research?**

A. No. *Unit* costs are *supposed* to grow by less than input price inflation. That's what productivity growth accomplishes. Dr. Dismukes has once again ignored the cost impact of growth in operating scale. The conclusion is inescapable that power distributors require considerable revenue growth each year to keep pace with cost growth.

Q. **How do you respond to Dr. Dismukes' discussion of average use trends on pages 53-54 of his testimony?**

A. Dr. Dismukes tries to distract attention from the obvious slowdown in average use growth by comparing FG&E and Massachusetts to the U.S. The growth in average use by commercial customers is clearly slower in Massachusetts than in the US. As for residential customers, Dr. Dismukes has once again chosen a sample period for his calculations that provides a misleading impression. In the absence of large DSM programs, Massachusetts could very well experience material growth in residential average use because electricity has expanding uses in a comparatively affluent and tech savvy residential sector. What matters is the average use trends in *more recent* years, during which Massachusetts has implemented unusually aggressive and effective conservation policies. Although his data are not weather normalized and the sample period is short, it is noteworthy that from 2008-2011 the average use trends of the residential customers of Massachusetts have been below the US norm.

I would also like to note that in computing average use trends it is irregular to remove a few years of declining average use but keep the "rebound" years that follow. In addition to an improved economy, the remarkable rebound in average use that occurred in 2010 was due in part to the transition from cool to hot summer weather.

Q. Dr. Dismukes believes that due to revenue decoupling, there is "virtually no way" that the Company could be unable to earn a return on and of its "test year investments". Is that evidence that revenue decoupling undermines the Company's need for a CCAM or PBR as he asserts?

A. No. Decoupling does ensure that a utility will recover its cost in the historical test year, as adjusted for known and measurable changes. However, it does not compensate the

Company for the all but inevitable *growth* in its cost between rate cases. Absent a broad-based RAM, utilities will be compelled to file frequent rate cases.

Q. Dr. Dismukes asserts on page 38 that the Company's proposed productivity offset is "far lower than offsets currently utilized in most U.S. PBR programs" and as a result is not "an effective productivity offset". Are those fair comments?

A. No. My research suggests an X factor of 0.01% is appropriate for FG&E. This is only modestly lower than the X factors the Department approved for Boston Gas (0.50% and 0.41%) and Bay State Gas (0.51%) after reviewing extensive productivity evidence.[6] The price cap plan for NSTAR Electric had an X factor that averaged 0.63% over the plan term. It was the outcome of a settlement where parties were informed by a productivity study I prepared for NSTAR.

The X factor suggested by my research is lower than those thus far approved due in part to the slower growth in the revised GDPPI that I discussed earlier in my testimony. Much of the remaining difference is due to a 0.20% stretch factor. This is lower than those previously approved in Massachusetts but based on solid reasoning since the peer group experienced rate cases every 5-6 years on average during the sample period. The benefits of stronger performance incentives are built into the industry productivity trend. I should also note that my research for FG&E is based on an improved treatment of capital cost that produces more stable input price indexes that make it possible to calculate an input price differential with greater precision. There is less reason to ignore input price differentials out of concern about volatility.

[6] The Bay State Gas X factor reflected the productivity research in the second Boston Gas PBR filing.

I should also note that the PBR plan for NSTAR was a *price* cap plan (as is the soon-to-expire plan of Central Maine Power). The X factor appropriate for a *revenue* cap index in 2013 should not be expected to be the same as one approved for a *price* cap index five to ten years ago. A productivity index appropriate for use in the design of a price cap index for a power distributor should employ an output treatment that is sensitive to the trend in residential and commercial ("R&C") average use. As recently as 2007, the historical trend in R&C average use that might enter into a productivity calculation was still materially positive in the northeast US. However, this growth trend has since vanished. Thus, even if FG&E was filing for a price cap plan, research would support a slower MFP growth trend.

Q. Are there recent precedents for low X factors in PBR plans based on index research?

A. Yes. The Ontario Energy Board recently approved a base productivity growth target of zero in a PBR plan for provincial power distributors.[7] Many of these distributors are small companies like FG&E. The stretch factor for a distributor with average cost efficiency will be 0.30%. There was no need to reduce X by the productivity trend of the Canadian economy (which is, in any event, close to zero) because the Board approved an industry-specific inflation measure.

Q. Are there other considerations that would reduce the level of a productivity offset in the Company's proposal compared to historic PBR plans?

A. Yes. Several considerations are pertinent here.

[7] Ontario Energy Board, *Report of the Board: Rate Setting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (November 2013).

- In the interest of economy, I did not develop a highly tailored peer group for Unitil and instead reported only research results for a broad northeast peer group that includes numerous utilities in the mid-Atlantic states. The MFP trend for the "upper" Northeast, which I define as upstate New York and New England, is considerably slower over the same sample period. I recently presented results for an upper Northeast peer group in testimony in Maine, where this group has been favored by Commission Staff in power distribution PBR filings. For the same 2002-2011 sample period used in this proceeding, I found that the average annual growth rate in the MFP trend of power distributors in the upper Northeast was only 0.56%.
- Table 1 of my direct testimony shows that the MFP trend of the sampled distributors has been much slower on average since 2006 than in earlier years of the sample period. The full 10 year sample period smooths index volatility but materially raises the X factor. We do not fully understand the reason for the productivity growth slowdown, and there is a possibility that productivity growth in the next five years will not revert to the longer term trend.
- The proposed RCI does not include a customer growth trend.

All of these considerations suggest that the proposed X factor is quite fair to customers. Should the Department nonetheless choose a higher X factor, fairness is served by also adding a customer growth term to the RCI.

Q. On page 39 of his testimony, Dr. Dismukes also notes the absence of an accumulated inefficiencies factor in the Company's proposal. Is this a valid concern?

A. No. Accumulated inefficiencies factors are rare in PBR plans, and there is no reason to believe that FG&E deserves one in addition to the stretch factor which it has proposed.

The accumulated inefficiencies factor included as part of the original Boston Gas PBR plan was overturned on appeal. No subsequent energy utility PBR plan in Massachusetts has included such a factor.

Q. Please summarize your views on the Company's proposed revenue cap index.

A. The Company's PBR proposal combines the considerable advantages of PBR and revenue decoupling. The use of PBR to escalate allowed revenue was expressly sanctioned in the Department's generic decoupling decision and does not require extraordinary business conditions to be warranted. An RCI would help to compensate FG&E for the combined effects of DSM and decoupling on its ability to fund cost growth without rate cases. There would be strong public policy arguments for PBR even in the absence of decoupling as a means to incent better performance with lower regulatory cost. Even Dr. Dismukes notes in his direct testimony that an appropriately defined PBR plan can be an effective form of alternative regulation. The proposed RCI is based on quality, unbiased research and the plan overall provides real benefits to customers. A small utility like FG&E is well-suited for a return to PBR because there are special benefits for the Company and its customers from a reduction in rate case frequency. PBR and revenue decoupling are both good ideas, and together provide an excellent system for the regulation of Massachusetts power distributors.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.