COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 10-55

REBUTTAL TESTIMONY OF DR. LAWRENCE R. KAUFMANN

IN SUPPORT OF

O&M NET INFLATION ADJUSTMENT MECHANISM

EXHIBIT NG-LRK-Rebuttal-1

July 21, 2010

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lawrence R. Kaufmann. My business address is 22 East Mifflin, Suite 302, Madison, WI, 53703.

Q. Have you previously filed testimony in this proceeding on National Grid's (the Company's) proposed operations and maintenance (O&M) net inflation adjustment mechanism?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will: (1) evaluate the Attorney General's arguments against terminating the Company's current performance-based regulation (PBR) plan; (2) respond to the alleged "deficiencies" in the partial factor productivity (PFP) and input price analysis presented in my Direct Testimony; and (3) analyze Dr. David Dismukes' "alternate PFP adjustment factor."

Q. What is your general assessment of the Attorney General's testimony on these issues?

A. On the first issue, none of the Attorney General's arguments opposing the termination of the PBR plan have merit. There is no theoretical or other evidence that terminating the existing plan will harm incentives. Terminating the existing PBR will not create new regulatory challenges or impact clean energy initiatives. In fact, the Boston Gas PBR plan has been in effect for seven years, which makes it one of the longest in

North America, while also meeting the "minimum time horizon." The Attorney General's recommendation to retain the PBR plan is also inconsistent with the Department's findings on this issue, as most recently stated in Bay State Gas Company, D.P.U. 09-30 (2009).

Second, the alleged "deficiencies" in the Company's proposed O&M net inflation factor asserted by Dr. Dismukes are entirely without foundation. There is no "mismatch" in the data used to develop weights. Dr. Dismukes also does not appear to understand how these weights were used and draws several erroneous conclusions regarding the underlying analytical work. The sample coverage exceeds what the Department has found to be reasonable in other proceedings, and any unreported information in the available dataset is not affecting the recommended value for the X factor in the O&M net inflation adjustment mechanism.

Third, there are significant flaws in Dr. Dismukes' recommended alternate O&M adjustment formula. His recommended X factor formula is not consistent with the actual value that he recommends for the X factor. Incorporating the information that is needed to resolve this inconsistency leads to a recommended X factor of – 1.59 per cent, or an annual O&M adjustment of GDP-PI inflation *plus* 1.59 per cent, which is not reasonable. His recommended PFP and O&M input price measures are also characterized by aggregation bias, and therefore, are less precise and accurate than my estimates of these parameters. Dr. Dismukes' proposal to resurrect the accumulated inefficiencies factor is also conceptually and empirically unfounded and will include at least some double-counting with his 0.6 per cent recommended value for the consumer dividend.

Q. How is your testimony organized?

A. The introduction to my testimony is presented in Section I. Section II summarizes the Attorney General's arguments against terminating the PBR Plan currently in effect for the Boston Gas (BOS) system. The following five sections present my evaluation of these Attorney General arguments. Section III evaluates whether the termination of the existing BOS PBR plan will harm the Company's performance incentives. Section IV discusses the length of the BOS PBR plan relative to other approved plans for energy utilities. Section V evaluates relevant Department precedents. Section VI examines the BOS returns and capital spending while it has been subject to PBR. Section VII briefly summarizes my assessment of the Attorney General arguments opposing the termination of the existing PBR plan.

The following sections turn to Dr. Dismukes' analysis of the O&M net inflation adjustment formula. Section VIII evaluates Dr. Dismukes' criticisms of my PFP and input price research, which is used to support the recommended X factor for the Company's proposed O&M net inflation adjustment formula. Section IX discusses Dr. Dismukes' proposed X factor formula and whether or not it is consistent with his empirical X factor recommendation. Section X assesses Dr. Dismukes' alternate

O&M PFP and input price research. Section XI examines Dr. Dismukes' proposal to include an accumulated inefficiencies factor (AIF) as a component of the X factor. Section XII summarizes my assessment of Dr. Dismukes' technical assertions and his alternate X factor recommendation for the O&M net inflation mechanism.

II. EXISTING PBR PLAN

Q. Please provide a brief overview of the existing PBR Plan applicable to the Boston Gas system.

A. BOS currently operates under a PBR plan that took effect on November 1, 2003 and was approved by the Department for a 10-year term. Under the plan, BOS's allowed base distribution rates are adjusted annually to reflect inflation in the GDP-PI index minus an X factor of 0.41 per cent. The plan also includes other features such as an earnings sharing mechanism, which factors earnings deficiencies under a 6 percent return on equity, and excess earnings over a 14 percent return on equity, into the annual price change.

Q. Is National Grid proposing to continue its existing PBR Plan in conjunction with its proposed revenue decoupling mechanism?

A. No. National Grid is proposing to terminate its existing PBR plan and, instead, apply formula-based adjustments to O&M costs only. The O&M net inflation adjustment mechanism would adjust base rates annually to reflect anticipated changes in O&M costs. Each year, the net inflation adjustment mechanism would update the

Company's approved test year O&M expenses (excluding some specified items) for inflation in the GDP-PI index minus an X factor of 0.52 per cent.

Q. Does the Attorney General support the Company's proposal to terminate its existing PBR plan?

A. No. The Attorney General has filed testimony from three witnesses (Dr. David Dismukes, Dr. Alvaro Pereira, and Mr. Timothy Newhard) who oppose the Company's proposal to terminate its existing PBR plan. All three witnesses support a continuation of the existing PBR plan in conjunction with the Company's proposed revenue decoupling mechanism.

Q. What specific criticisms does Dr. Dismukes make regarding the proposed termination of the PBR plan?

A. Dr. Dismukes says "long time periods" are a commonly recognized design characteristic for PBR plans (Exhibit AG-DED-1 at 7, lines 6-8). Dr. Dismukes also says "a commitment by all parties – regulators, ratepayers, and regulated companies – is usually considered a pre-requisite to attain the optimal benefits from PBRs" (at 7, lines 20-22). Dr. Dismukes cites two academic articles (at 8, lines 8-16), which he claims show that "unscheduled reviews" and "a multi-period (changing) PBR" will either undermine incentives or create perverse incentives. Dr. Dismukes further claims that "if the Department allows the Companies to effectively change their PBR without any reciprocal and symmetric ratepayer benefits, it raises a broad range of regulatory policy challenges including challenges to current clean energy policy initiatives that require long-term commitments" (at 8, lines 19 through 9, line 1). Lastly, Dr. Dismukes says that the Department's generic incentive regulation proceeding "required fixed time horizons for PBR plans" (at 9, line 5).

Q. What specific criticisms does Dr. Pereira make regarding the proposed termination of the PBR plan?

A. Dr. Pereira makes three specific criticisms. First, he says "termination of the plan will have negative unanticipated consequences to ratepayers" (Exhibit AG-AEP-1 at 2, 24-25). Second, Dr. Pereira says he does not see any evidence that the current PBR plan is not providing just and reasonable rates to Boston Gas. Lastly, Dr. Pereira says "fulfillment of the PBR's full term will not adversely affect the implementation of the Company's three-year energy efficiency plan," which was approved by the Department (at 2, line 28 through 3, line 1).

Q. What specific criticism does Mr. Newhard make regarding the proposed termination of the PBR plan?

A. Mr. Newhard says terminating the PBR plan "will undermine the incentives that the Department built into the long-term rate plan to make Boston Gas more efficient and keep down costs to the company and rates for its customers. Moreover, Mr. Newhard claims that, if the Department allows Boston Gas Company to "break" the 10-year rate plan, it will cause "significant and permanent harm to customers" (Exhibit AG-TN-1, at 6, lines 11-15). Mr. Newhard then develops an estimate of the alleged harm to customers resulting from termination of the PBR plan.

III. TERMINATING THE EXISTING PBR AND INCENTIVES

Q. All three witnesses sponsored by the Attorney General in opposition of the Company's proposals claim that, if the existing Boston Gas plan does not remain in effect for the originally approved term of 10 years, it will undermine incentives in a way that harms customers. Do you agree?

A. No.

Q. Please explain.

A. Evaluating whether the proposed termination of the current BOS PBR plan will adversely impact the Company's incentives is a two-step process. First, it is necessary to understand why the premature termination of PBR plans can, in theory, potentially lead to a diminution of performance incentives. Next, the analyst must assess whether these theoretical concerns are, in fact, applicable to the termination of this particular PBR plan. The Attorney General's witnesses have not undertaken this type of analysis, nor have they presented any specific evidence or concrete examples to support their claim that terminating the current BOS PBR plan will undermine National Grid's incentives. Instead, all three witnesses have, in essence, asserted that incentives will be undermined and, in Dr. Dismukes' case, he has cited to nothing more than two published articles to support this opinion. I believe a more comprehensive analysis of these issues shows that the termination of the current BOS PBR plan will not have any undesirable implications for the Companies' performance incentives.

Q. Please explain the theoretical concerns related to the premature termination of PBR plans.

A. My analysis of this issue will draw on my own theoretical and applied research on the relationship between performance incentives and the design of incentive regulation plans. This work has been undertaken with others in Pacific Economics Group (PEG). In particular, PEG has developed an "incentive power model" that can quantify and compare the incentives that are created under literally thousands of alternative incentive regulation plans. This model has been developed and refined over a number of years, in consulting projects for both utilities and regulatory Commissions. In this proceeding, I have provided a copy of one incentive power report, in response to Information Request DPU-1-7.

PEG's incentive power model shows that the performance incentives created by a PBR plan depend critically on three design features: 1) the amount of time the PBR plan is in place; 2) how benefits are shared with customers while the plan is in effect; and 3) how benefits are shared with customers when the plan is updated. These results are intuitive. Incentives under PBR are created by utilities' ability to profit from improvements in their efficiency. All else equal, utilities will profit more from efficiency-boosting initiatives when they retain a greater share of the resulting cost savings, and when these cost savings are retained for longer periods of time.

However, a utility's expectations about the future benefits it is allowed to retain can, in principle, be frustrated if PBR plans are terminated prematurely. For example, suppose a utility is making very large profits under a PBR plan, and public pressure leads a regulator to intervene while the PBR plan is in effect and reduce the company's rates and thereby reduce what are deemed to be unreasonable returns. Such an "unscheduled" intervention would effectively distribute the utility's efficiency gains to customers before the planned review date for the PBR plan, which was when the utility expected those gains to be passed through to customer rates. If such an intervention occurs, the utility will be more cautious about pursuing efficiency gains in the future, since it will not want to invite another unscheduled regulatory review and adjustment of its prices. Thus, a premature adjustment of the terms of a PBR plan can have a negative impact on the Company's performance incentives going forward. The most extreme form of such an unscheduled regulatory intervention would be a premature termination of the entire PBR plan.

Q. Have unscheduled reviews of PBR plans ever occurred?

A. Yes. Perhaps the best known example occurred in Britain in 1995, when the price controls that applied to British electricity distributors were adjusted only one month after the regulator completed his review of an expiring set of PBR plans and announced the terms of a new set of plans. Some public reaction to the regulator's decision was unfavorable, and this prompted an unscheduled review of the just-announced PBR plans, which in turn led to a new round of price cuts and an increase in the distributors' X factor.

Q. Is the "unscheduled reviews" issue addressed in any of the articles cited by Dr. Dismukes?

A. Yes. Dr. Dismukes references an October 2001 article in the *Electricity Journal* which he terms "the Sappington article." In response to the question "Has any of the literature recognized the problems that can arise in re-setting regulatory performance periods," Dr. Dismukes says that "(t)he Sappington article cited earlier notes that 'unscheduled reviews and other attempts to expropriate gains should be avoided, or the viability of future regulatory plans will be threatened" (at 8, lines 8-12).

Q. Is the point referenced in the Sappington article relevant to the current proceeding?

A. No. National Grid's current base rate filing is necessary to comply with the Department's Order in D.P.U. 07-50-A. The Department has said that all distributors in Massachusetts must file revenue decoupling proposals which include "a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design" (DPU 07-50-A, at 84). Although a base-rate proceeding in 2010 was not necessarily anticipated when the BOS PBR plan was approved in 2003, this rate filing has not been motivated by attempts to "expropriate gains" made by the Company. Dr. Dismukes' reference to "unscheduled" regulatory reviews is therefore irrelevant.

Q. **Dr. Dismukes cited another article from the incentive regulation literature. Is this other article relevant to the proposed termination of the existing BOS PBR plan?**

A. No. In fact, this article is far less relevant for evaluating the proposed termination of the existing BOS PBR plan than the Sappington article.

Q. **Please identify this article and summarize Dr. Dismukes' discussion of its implications.**

A. The second article that Dr. Dismukes cites is "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator." It was written by Dr. Peter Navarro and published in 1996 in the *Yale Journal of Regulation*. Dr. Dismukes says that this article "notes that a multi-period (changing) PBR, unlike a longer-run policy-consistent single-period PBR, is likely to give a utility "significant incentives and opportunities to 'game' the PBR system" in order to maintain its operations at an average cost greater than the traditional single period PBR outcome" (at 8, at 13-16). Thus, in his summary of the Navarro article, Dr. Dismukes contrasts the incentives associated with a "multi-period (changing) PBR" with those resulting from "a longer-run policy-consistent single period PBR."

Q. **What does Dr. Navarro say in this article about the incentives resulting from "single period" and "multi-period" PBR?**

A. It is not clear to me that Dr. Navarro uses the precise terminology referenced by Dr. Dismukes, nor does Dr. Dismukes define what he means by this term. Dr. Navarro says that, in a theoretical multi-period PBR setting, firms can behave strategically in ways that may be counter to the objectives of incentive regulation. The most important source of such strategic behavior (which has been noted in both the literature and some incentive regulation plans, particularly overseas) is that firms can conserve on their capital spending while the PBR plan is in effect, but then undertake a significant amount of capital spending in the "test year" or years which will establish starting prices at the beginning of the next PBR plan. In this scenario, the utility may have simply deferred capital spending, rather than reduced capital spending, over the entire term of the PBR plan. Dr. Navarro notes that analyzing strategic behavior of this kind can be analytically complex, but summarizes his views as follows:

> "While the results of this (strategic) calculus are theoretically indeterminate and no doubt specific to each firm and its regulatory environment, at least one thing should be clear: *PBR is generally less likely to be successful at motivating cost minimization in a multi-period framework of continuing regulation than in the "one period and deregulate"* model" (at 147, italics in original).

Q. Does Dr. Navarro's theoretical concern pertain to whether or not an existing PBR plan is terminated prematurely?

A. Absolutely not. It is clear from the italicized passage above that Dr. Navarro is making a very different point. He is contrasting a "multi-period framework of continuing regulation" with a "one period and deregulate model." His point is that strategic concerns are largely, if not entirely, eliminated when PBR is used as a transitional type of regulation on the path to ultimate deregulation of the industry. PBR can be used in this way for some utility services, such as certain telecom services which were once regulated but are now provided in entirely competitive markets. However, this is not the case for gas distribution, which will remain subject to "continuing regulation" for the foreseeable future (and, unless there are significant changes in the underlying technology of gas delivery, in all likelihood in perpetuity). Thus, Dr. Navarro is contrasting the potential for strategic behavior in *any* PBR framework where utilities remain regulated, relative to a situation where PBR is a transitional regulatory strategy on the road to deregulation. Whether or not a PBR plan is terminated before the planned end-date has no bearing on Dr. Navarro's discussion of these issues.

Q. Do you believe National Grid has exhibited strategic behavior of the kind discussed by Dr. Navarro?

A. No. On the contrary, I believe the Attorney General has presented evidence which shows that National Grid is not undertaking strategic behavior of the kind that motivated Dr. Navarro's theoretical concerns.

Q. Please explain.

A. In Exhibit AG-AEP-1 at 9, line 14 Dr. Pereira presents data on Boston Gas's actual and budgeted capital spending in each year from 2000 through 2009. Boston Gas was subject to PBR in each of these 10 years. These data show that Boston Gas's actual capital spending exceeded what the Company budgeted in eight of the 10 years. On average, Boston Gas spent $11.9 million more than what was budgeted in each year, or about 10% more than the budgeted amount.

This is exactly the opposite of what would be expected if the Company was "strategically" managing its behavior under PBR. If Boston Gas had chosen to act strategically, it would have "underspent" on capital in nearly every year that the PBR plan was in effect. The fact that Boston Gas has consistently and substantially spent more than what was originally budgeted for capital is compelling evidence that the strategic concerns that Dr. Navarro says can exist in theory have not, in fact, been manifested under the BOS PBR plans.

Q. Do Dr. Pereira or Mr. Newhard provide additional arguments or evidence to support their opinion that terminating the Company's PBR plan will undermine the Companies' incentives?

A. No, and I am not aware of any additional arguments that can even be raised in theory. In my opinion, the only such concern is the one discussed in connection with the Sappington article. Although "unscheduled reviews" can theoretically undermine the incentives of PBR plans, this issue is not relevant to National Grid's current proposal to terminate its PBR plan.

Q. Do you agree with Dr. Dismukes that the termination of the existing PBR plan will raise a number of regulatory policy challenges, including challenges related to clean energy initiatives that require long-term commitments?

A. No. Logically, the Company's commitment and incentives to pursue clean-energy initiatives depends on the revenue decoupling mechanism, not the PBR mechanism. With an effective revenue decoupling mechanism in place, the disincentive to pursue energy conservation, demand management and other clean energy initiatives will be removed for National Grid.

It is also worth noting that the Department views revenue decoupling as a long-term initiative, but D.P.U. 07-50 did not require distributors to submit revenue decoupling mechanisms with fixed terms. I believe the lack of a mandatory, fixed term for decoupling mechanisms further weakens the Attorney General's position that clean energy initiatives require the BOS PBR plan to run for its originally approved term. The Department has not required "clean energy" efforts to be pursued in conjunction with fixed-term decoupling mechanisms, let alone fixed-term PBR plans.

Q. Do you agree with Dr. Pereira that "fulfillment of the PBR's full term will not adversely affect the implementation of the Company's three-year energy efficiency plan"?

A. I do, but I also agree with the converse position: terminating the existing PBR plan will not adversely affect the implementation of the Company's energy efficiency plan. Again, this is because the incentives to pursue clean energy are linked logically and operationally to the revenue decoupling mechanism, not the PBR plan. Whether or not the current BOS PBR plan is terminated will have no impact on the Company's ability or commitment to pursue clean energy goals.

IV. THE TERM OF THE EXISTING PBR PLAN

Q. Do you agree with Dr. Dismukes that "long time periods" are "a commonly-recognized design characteristic for a PBR" plan?

A. Yes, I do. My incentive power research shows that the strength of incentives is positively related to the length of the PBR plan. I also believe the current Boston Gas plan clearly qualifies as having been in effect for a "long time period," even if it is terminated in November 2010.

Q. What is the basis for this conclusion?

A. This conclusion is based on a review of approved, multi-year regulatory plans for energy utilities in North America. Schedule NG-LRK-Rebuttal-1 presents summary information on 96 multi-year or index-based regulatory plans that have been approved in the US and Canada. Every one of these plans allows for rate adjustments while the plan is in effect, either through formula-based adjustments or rate trajectories that recover a utility's forward-looking cost of service.

The Boston Gas plan was approved in 2003, and when this rate proceeding is concluded in November 2010 it will have been in effect for seven years. For the 96 plans presented in Schedule NG-LRK-Rebuttal-1, the average term of the approved incentive regulation plan is 3.48 years. The existing BOS plan has therefore already been in effect more than twice as long as the average, multi-year or index-based regulatory plan in North America.

In addition, if the existing BOS plan is terminated in November 2010, only three other PBR plans will have had longer terms. These plans are for Bangor Gas in Maine (12 years), Enmax in Alberta, Canada (9 years), and Berkshire Gas in Massachusetts (a 31 month rate freeze, followed by approximately 7.5 indexing years). Thus, even if the existing BOS PBR plan is terminated, it will have been in place for a longer period of time than more than 93% of the approved multi-year or indexing regulatory plans in North America.[1]

Given this experience, I believe that the term of BOS PBR plan clearly already qualifies as "long." This issue can only be judged by the practical standards that are used by regulators in the industry, not by theoretical notions. The Boston Gas PBR plan has already been in effect for a very long time by the standards of energy utility industries. The extended length of this plan can be expected to have created strong incentives for BOS to contain its costs. Terminating this PBR plan in 2010, rather than in 2013, also does not undermine the Companies' incentives or create new, perverse incentives.

[1] If the Boston Gas PBR is terminated, it will essentially be tied for fourth place with two other plans that also have or are planned to have seven year terms: NStar Electric in Massachusetts and Central Maine Power's first electricity distribution PBR plan. Thus, at least 90 of the 96 plans, or 93.75% (= 90/96) of plans, will have had shorter terms than seven years. The actual number may even be higher, because these estimates assume that all existing plans will run their entire term.

Q. Do either of the articles cited by Dr. Dismukes discuss how long PBR plans should be to create strong incentives?

A. Yes. The Sappington article discusses this issue. Although not providing a definitive recommendation, this article does say that a "period of moderate length (e.g. five years)…can provide strong incentives while minimizing the risk of unacceptable outcomes."[2] Since the BOS plan has already been in effect for seven years, the Sappington article cited by Dr. Dismukes actually supports the opinion that the BOS PBR plan has already been in effect for a long enough period of time to create strong performance incentives.

V. DEPARTMENT PRECEDENTS

Q. Dr. Dismukes says that, in its generic incentive regulation proceeding, the Department "required fixed time horizons for PBR plans in order to permit companies to implement long-term business strategies that could produce significant cost savings and other benefits to ratepayers and shareholders." Do you agree with this statement regarding the Department's policy in the generic incentive regulation proceeding?

A. Not entirely. Dr. Dismukes references page 55 of D.P.U. 94-58 to support this opinion. This page presents the Department's conclusion in the generic incentive regulation proceeding, which provides ten conditions that an incentive mechanism should satisfy. None of these conditions requires "fixed time horizons," but condition

[2] Sappington et al (2001), "The State of Performance-Based Regulation in the U.S. Electric Utility Industry," *Electricity Journal*, p. 78. The ellipsed passage in this quote contains the phrase "coupled with well-designed earnings sharing rules and clearly defined pass-through provisions." These features are not relevant to creating strong incentives *per se* and, in fact, it is well-known that earning sharing mechanisms weaken rather than strengthen incentives. Instead, these features of PBR plans help to minimize "the risk of unacceptable outcomes" that the authors mention.

eight does say an incentive mechanism should "have a minimum time horizon to give the incentive plan enough time to achieve its goals." A "minimum" time horizon is conceptually distinct from a "fixed" time horizon, and the concepts can have different implications for the incentives created by the PBR framework. For example, a series of five, two-year PBR plans that run sequentially will almost certainly create weaker incentives and lead to higher customer rates than a single ten-year plan which is terminated in year seven. The first example would be consistent with "fixed" time horizons that are nevertheless less than the "minimum time horizon to give the incentive plan enough time to achieve its goals." The latter example clearly allows for a longer time horizon and is more likely to satisfy the criterion the Department actually established for incentive regulation plans.

Q. Do you believe the seven years that the current BOS PBR plan has been in effect complies with the Department's "minimum time horizon" requirement?

A. I do. I believe this is evident from the PBR plans that the Department has actually approved since D.P.U. 94-58. The first Boston Gas PBR plan approved in D.P.U. 96-50 had an intended term of five years, although it actually ran longer. The PBR plan approved for Blackstone Gas in 2004 had a term of five years. The PBR plan approved for NStar electric had a term of seven years. Although the Department clearly has a preference for PBR plans with even longer terms, the issue with respect to compliance with the requirements specified in D.P.U. 94-58 is what constitutes the "minimum time horizon" for a PBR plan. Since the Department has in fact approved plans with terms of seven or fewer years, I believe that the seven years that the BOS plan has already been in effect satisfies this criterion.

Q. Are any other Department precedents relevant for evaluating the Company's proposal to terminate its PBR filing?

A. Yes. The Company's current base rate filing was encouraged by the Department's Order in D.P.U. 07-50-A. Since that proceeding, the Department has ruled on the compatibility of existing PBR plans and proposals to increase base rates in conjunction with the establishment of revenue decoupling mechanisms. None of the Attorney General witnesses reference these recent Department precedents which, in my opinion, indicate that the Company had no choice but to propose terminating its existing PBR plan to address its existing revenue deficiency and to fulfill the Department's policy goals.

Q. Please explain.

A. In D.P.U. 07-50-A, the Department stated that energy distributors in Massachusetts should present revenue decoupling proposals by the end of 2012. Furthermore, D.P.U. 07-50-A says that revenue decoupling proposals must include "a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design." The first revenue decoupling proposal that the Department ruled on was in D.P.U. 09-30, for Bay State Gas. Bay State presented a revenue decoupling proposal with a base rate cost of service filing. Bay State's cost of service analysis indicated a revenue deficiency, so it proposed a base rate increase. Bay State was also subject to a PBR plan approved in D.T.E. 05-27, and Bay State proposed to continue this PBR plan.

In its Order on Bay State's filing, the Department found that Bay State's:

> filing and request for a base rate increase is consistent with the Department's Order in D.P.U. 07-50-A. In that proceeding, we expressed a desire to avoid the implementation of decoupling in piecemeal fashion i.e. by permitting distribution companies to layer decoupling proposals on top of existing rates. D.P.U. 07-50-A at 81-82. As such, we concluded that, when a company files a proposal for a revenue decoupling mechanism it should do so in conjunction with the filing of a base rate proceeding. Id. at 82. The objective of this requirement was to ensure that rates would be set for decoupling purposes based on an understanding of the company's underlying distribution revenue requirement and an allocation of this revenue requirement among customer classes through an allocated cost of service study. Id. at 81. (D.P.U. 09-30, at 21)

. Thus, Bay State's filing for a request to increase its base rates was consistent with the Department's policy. In fact, the Department explicitly decided against "permitting distribution companies to layer decoupling proposals on top of existing rates" and required utilities to submit a distribution cost of service analysis in conjunction with revenue decoupling proposals. At the same time, the Department found that

> "(t)he establishment of new rates based on a new test year of costs and revenues completely changes the dynamic of the Company's (PBR) rate plan…the components of the Company's PBR plan, including its price-cap formula, are integrally related and, as such, are dependent upon each other to balance the benefits between shareholders and ratepayers. An interim change in rates, such as those based on an updated test year of costs and revenues, alters this balance. Based on these considerations, we conclude that the establishment of new base rates in this fashion subjects Bay State's existing rate plan to termination. The Company's ten-year rate plan, as approved by the Department in D.T.E. 05-27, no longer exists once new cast-off rates

> are established and, therefore, it is hereby terminated" (D.P.U. 09-20, at 22-23).

The Department's Orders in D.P.U. 07-50-A and D.P.U. 09-30 therefore established the following: 1) all energy utilities in Massachusetts must file revenue decoupling proposals; 2) all revenue decoupling proposals must include a base rate cost of service filing; 3) based on the Department's review of utilities' cost of service evidence, base rates can be increased before revenue decoupling takes effect; and 4) if utilities are operating under an existing PBR plan and their approved cost of service leads to an increase in "cast off" base rates, their existing PBR plan is terminated.

The cost of service filing that National Grid submitted in conjunction with its revenue decoupling proposal showed a revenue deficiency. The Company therefore requested an increase in its base rates. Given these facts, if the Company had proposed to continue its existing PBR plan, its filing would *not* comply with the Department's Order in D.P.U. 09-30. In fact, Bay State made an identical proposal to continue its PBR plan, and it was rejected by the Department. Given the Company's review of its cost of service and the mandate to file a revenue decoupling plan, in my opinion National Grid effectively had no choice but to propose terminating the existing BOS PBR plan as part of this proceeding.

VI. EARNED RETURNS AND CAPITAL SPENDING UNDER PBR

Q. Dr. Pereira claims that the rates produced by the current BOS PBR plan are just and reasonable. Do you agree?

A. No. I do not believe that Dr. Pereira can provide an opinion on whether the Boston Gas or other National Grid companies' rates are just and reasonable unless he has reviewed the Companies' entire cost of service filing in detail. There is no evidence that he has done so, since he supports his view with information on earnings that the Company achieved while it was under PBR, as well as the relationship between Boston Gas's actual and budgeted capital spending while it was subject to PBR.

Q. Notwithstanding the incomplete nature of the evidence Dr. Pereira has presented, do you believe it tends to support the conclusion that the Company's current rates are just and reasonable?

A. On the contrary, the evidence Dr. Pereira presents suggests the opposite. He presents data (at 8, line 1) showing that Boston Gas has earned less than its allowed ROE of 10.2% for every year that its PBR plan has been in effect. The average BOS ROE from 2003 through 2008 was 7.4%, which is 280 basis points below its allowed ROE. Under either a performance-based or conventional cost of service regulatory framework, I do not believe it is reasonable for utilities to show earnings that average 280 basis points below their approved cost of equity for six consecutive years and not have the opportunity to file for a rate increase.

Q. Dr. Pereira also claims that Boston Gas data show "that despite the price (and cost) controls imposed by the PBR, the Company has been able to maintain a high level of capital spending." Do you believe that this is the most reasonable interpretation of the data presented by Dr. Pereira?

A. No. I do not think it is reasonable to look at Boston Gas's capital spending data in isolation. Dr. Pereira should also consider the data he presented on the Company's earnings while it was under PBR. Considering both trends simultaneously, it is clear that BOS chose to spend more than its capital budgets even though it was under-earning and, accordingly, under strong pressure from shareholders to conserve on capital spending. The fact that BOS consistently spent above budget shows that it believed capital spending was necessary to achieve goals, such as providing safe and reliable service, that were at least as important as generating appropriate shareholder returns. Regulation should be structured to encourage safe and reliable service to customers and reasonable returns to shareholders, and if those goals are in conflict – as the data presented by Dr. Pereira indicate - then I believe a review of the plan is warranted.

VII. SUMMARY ANALYSIS OF ATTORNEY GENERAL ARGUMENTS

Q. Please summarize your analysis of the Attorney General' arguments against terminating the existing BOS PBR plan.

A. The Attorney General has advanced a number of arguments against terminating the existing BOS PBR plan, but none are persuasive. There is no theoretical or other evidence supporting the view that terminating the existing plan will harm the Company's incentives. Terminating the existing PBR also does not create new regulatory challenges or impact clean energy initiatives. The PBR plan has already been in effect for seven years, which makes it one of the longest in North America. A seven-year term appears to satisfy the Department's "minimum time horizon."

In addition, the Attorney General's position seems incompatible with Department policy. The Department will clearly decide whether and how much to adjust the Company's base rates, but it has ordered National Grid to file cost of service evidence as part of its revenue decoupling proposal. The Attorney General appears to be asking the Department to disregard this evidence and simply continue with the existing PBR plan, which is clearly inconsistent with D.P.U. 07-50-A. Moreover, if the Department finds that a base rate increase is warranted for National Grid, its analysis and conclusions in D.P.U. 09-30 imply that the existing BOS PBR plan must simultaneously be terminated.

However, performance-based plans can still advance the regulatory objectives of promoting cost efficiency and least cost utility services. Although it was necessary for the current rate filing to propose terminating the existing PBR, National Grid has transitioned to a new incentive regulation approach that is more consistent with its current circumstances. A key component of this new approach is the net inflation O&M adjustment mechanism. I will now turn to Dr. Dismukes' criticisms of my O&M input price and productivity research, which is the basis for the Company's recommended O&M net inflation adjustment formula.

VIII. ASSERTIONS MADE BY DR. DISMUKES

Q. What were Dr. Dismukes' specific criticisms of the O&M input price and productivity research?

A. Dr. Dismukes said there three "deficiencies" in my O&M input price and productivity work. They were: 1) a mismatch in companies used in developing various weights and factors; 2) questionable data quality for the information used in the analysis; and 3) a number of missing and unaccounted for variables in the dataset.

Q. Is there any validity to Dr. Dismukes' criticisms?

A. No.

Q. Please discuss Dr. Dismukes' "mismatch" concern.

A. In his testimony, Dr. Dismukes says that "one of the main drivers" of my O&M input price and productivity research was "an estimate of the typical O&M expense allocation across various different O&M accounts. This expense allocation is used to distribute the primary aggregate O&M cost information across various O&M subaccounts. However, the Companies did not restrict the development of these expense account weights to just northeastern LDCs but used the entire sample of LDCs included in the SNL database. So, instead of creating an expense profile based upon comparable LDCs operating in densely populated areas of the Northeast, the Companies' "peer" O&M expense profile weights includes such comparables as LDCs located in the Midwest (Missouri Gas Company), the plains of Nebraska (SourceGas), and the Rocky Mountains (Questar)" (Exhibit AG-DED-1, at 18, lines

2-12). Dr. Dismukes' responses to information requests reiterated these positions. For example, in response to Information Request NG-AG-2-12, Dr. Dismukes said his understanding of the "typical O&M expense allocation" profile is that "Dr. Kaufmann allocated O&M costs by sub-account to Massachusetts utilities based upon the average included in the SNL database."

Q. Is this an accurate description of your work?

A. No.

Q. Please explain.

A. Dr. Dismukes is fundamentally mistaken in asserting that I developed an "estimate of the typical O&M expense allocation across various different O&M accounts" that included "O&M expense profile weights" in order "to distribute the primary aggregate O&M cost information across various O&M subaccounts." In fact, I did not develop "O&M expense profile" weights or "distribute aggregate O&M cost information across various O&M subaccounts" at all. Instead, I developed weights using *actual* O&M cost data, which were then applied to Global Insight (GI) input price data in order to develop a more detailed and accurate measure of input price trends for the gas distribution industry.

The process for developing these weights was the following: first, I accessed actual gas distributor O&M data (excluding pension costs) that was broken down into a number of different cost categories. I then computed the share of each of these O&M

cost categories in the distributors' overall O&M costs, excluding pension costs. These O&M cost shares were then used as weights that were applied to the GI input price data. More precisely, I computed a non-labor O&M input price index as a weighted average of GI input price indexes for different gas distribution O&M cost categories, where the weight applied to a particular price index was equal to gas distributors' share of costs associated with that cost category.

It is true, however, that I used a national sample to compute the non-labor, O&M input price weights. This was also appropriate because the detailed GI input price indices are only available nationally, not for regional samples of gas distributors. National cost share weights are logically associated, and should be used, with national input price indexes. Thus, contrary to Dr. Dismukes' assertion, there would have been a "mismatch" in this portion of my analysis if I did *not* use national rather than regional information to develop the weights for the non-labor, O&M input price index.

Q. Please discuss Dr. Dismukes' concern with data quality.

A. Dr. Dismukes says "an additional shortcoming underlying the Companies' O&M expense profile is the absence of any kind of verification on whether the ranges included for these profiles are relatively comparable, much less reliable" (at 18, lines 15-16). He then presents some information showing variation among sampled distributors on different categories of O&M cost.

Q. Do you believe this is a legitimate criticism?

A. No. This point appears related to Dr. Dismukes' first concern about whether the sampled utilities used to allocate overall O&M expenses are "comparable," since both points stress the relative comparability of "expense profiles" across companies. However, as explained above, I did not use sampled data to allocate or distribute overall O&M cost data into various O&M subaccounts. Instead, I simply computed the actual shares of different O&M costs in overall O&M cost for sampled distributors. This exercise does not require that distributors be "comparable."

Dr. Dismukes also appears to question whether the data used in my analysis are accurate, and in response to Information Request NG-AG-2-14 he noted some minor discrepancies between the SNL data and the data reported in Massachusetts' distributors' Annual Reports. These Massachusetts Annual Reports present data on transmission and distribution O&M expenses and, therefore, are less accurate for the purposes of computing weights for calculating gas distribution input price trends than the distribution-only O&M cost database that SNL compiles. I have compared every data point that Dr. Dismukes highlighted in response to Information Request NG-AG-2-14 with those that SNL reports for the *sum* of transmission plus distribution expenses in the relevant O&M sub-account. In every case, the numbers are identical, and there is no discrepancy. Dr. Dismukes incorrectly concludes that there is a discrepancy because he is relying on a more aggregated (*i.e.* transmission plus distribution), and hence less accurate, cost measure than the distribution-only cost data that were used in my study. .

Lastly, my experience is that, in any cross section sample of US gas distributors, there is often significant variation in the share of O&M costs associated with different O&M cost categories. It certainly cannot be assumed that variation in O&M sub-accounts is evidence of data error, as Dr. Dismukes appears to suggest. One reason Dr. Dismukes has likely drawn this conclusion is that he incorrectly believes that I computed the sub-account data myself by applying nationwide "expense profiles" to individual utilities' overall O&M costs. This is simply not the case.

Q. Please discuss Dr. Dismukes' concerns about missing and unaccounted for variables in the dataset.

A. Dr. Dismukes implies my dataset should include "a complete number of companies and years." He says "a complete dataset for 124 companies over seven years should yield 868 observations," yet there are some instances of missing and random data reporting. He also says that "(s)ince the O&M expense profile is the result of an average of each observation's expense profile, a comparatively large company with only one entry would be under-represented within the average."

Q. Do you believe this is a legitimate criticism?

A. No. Again, it must be recognized that the national dataset was only used to compute weights that are used to develop the non-labor O&M input price index. The dataset that I used to estimate O&M PFP growth in the Northeast included 22 companies which together serve 76% of customers in the region. While this is not "entirely complete," it represents very substantial coverage of the Northeast gas distribution industry. It is also a more complete sample than I used in D.T.E. 03-40 when estimating TFP growth for Northeast distributors. In that proceeding, the Department rejected claims that my sample coverage was "non-representative" and found that I selected a sample which "given data limitations, balanced the objectives of comprehensiveness, heterogeneity and cost" (D.T.E. 03-40 at 475).

It is true that there are some missing data points in the available data, but I only selected companies where data was complete for the start and end-years of 1998 and 2008, respectively. Having missing data, or needing to interpolate data, in between sample end-points will not affect the computation of growth rates over the 1998-2008 period. Regarding the "comparatively large company" with a single data point being under-represented, Dr. Dismukes' point is again related to the computation of "expense profiles" that he believes were used to allocate O&M costs across sub-categories. This point is therefore irrelevant since I did not compute or use such expense profiles.

Q. Please summarize your review of Dr. Dismukes' critique of your O&M input price and productivity study.

A. Dr. Dismukes' critique is entirely without foundation. There is no "mismatch" in the data used to develop weights. Dr. Dismukes also does not understand how these weights were used, which leads to mistaken conclusions regarding the comparability among sampled companies and data quality. Finally, my sample coverage exceeds what the Department has found to be reasonable in other proceedings, and the sample has been selected so that any unreported information in the available dataset is not affecting my recommended value for the X factor in the O&M net inflation adjustment mechanism.

IX. DR. DISMUKES' RECOMMENDED X FACTOR FORMULA

Q. Dr. Dismukes has developed what he calls an "alternate PFP adjustment factor." Please summarize the X factor that Dr. Dismukes recommends in an updated O&M net inflation adjustment formula.

A. Dr. Dismukes recommends an X factor of 1.12 per cent for National Grid's O&M net inflation adjustment formula. He says this X factor is the sum of: 1) a net inflation differential of -1.03 per cent; 2) a productivity differential of 1.34 per cent; 3) a consumer dividend of 0.60 per cent; and 4) an accumulated inefficiencies factor of 0.2 per cent. This accumulated inefficiencies factor would only be in effect for three years. When it was removed after three years, the overall X factor would accordingly be 0.92 per cent.

Q. Does Dr. Dismukes present a formula for how his recommended X factor is to be calculated?

A. Yes. Dr. Dismukes presents a formula for computing the X factor in an O&M net inflation adjustment factor in Exhibit AG-DED-1 at 10, line 11. He also defines the components of this X factor at 10, lines 4 through 20.

Q. Please identify the components of the X factor in Dr. Dismukes' X factor formula.

A. Dr. Dismukes specifies and defines the following four components of the X factor:

> 1) An inflation differential, equal to the trend in input prices for the overall economy minus the trend in input prices for the gas distribution industry; minus
>
> 2) A productivity offset differential, equal to the difference between the O&M PFP trend for the economy minus the O&M PFP trend for the gas distribution industry; minus
>
> 3) A consumer dividend; minus
>
> 4) An accumulated inefficiencies factor.

In his response to Information Request NG-AG-2-8, Dr. Dismukes corrected this formula to add rather than subtract the consumer dividend and accumulated inefficiencies factors. In his response to Information Request NG-AG-2-20, Dr. Dismukes did not choose to make any other adjustments to his X factor formula.

Q. Is Dr. Dismukes' formula for computing the X factor consistent with the numerical value he recommends for the X factor?

A. No.

Q. Please explain.

A. Dr. Dismukes defines the "productivity offset differential" as the trend in O&M PFP growth for the economy minus the trend in O&M PFP growth for the gas distribution industry. He says his estimate of this productivity offset differential is 1.34 per cent. But in Schedule DED-1-8, it is clear that 1.34 per cent is Dr. Dismukes' estimate of PFP growth for the gas distribution industry itself; it is not the *differential* between the PFP growth for the overall economy and the gas distribution industry.

Q. Does Dr. Dismukes' present any information on the O&M PFP growth for the US economy in his testimony or responses to Information Requests?

A. No. In Response to Information Request NG-AG-2-19, Dr. Dismukes said "the partial factor productivity factor for the overall economy takes a value of zero." Dr. Dismukes therefore simply assumes a value of zero for the US O&M PFP growth term that appears in his recommended X factor formula.

Q. Is it reasonable to assume that US O&M PFP growth is zero?

A. No. The US government regularly computes metrics that can be used to estimate O&M PFP growth for the overall economy. The relevant measure is the growth in US labor productivity, which is computed by the US Bureau of Labor Statistics (BLS) within the US Department of Labor. In a macroeconomic context (*e.g.* for the entire US economy), productivity growth will be decomposed into labor and capital productivity growth, not alternate measures such as O&M PFP growth. The reason is that, in the overall economy, all returns to inputs are ultimately distributed to either labor or capital, not to "non labor" operations and maintenance inputs. However, US labor PFP growth corresponds to a comparable set of inputs as gas distributors' O&M PFP growth because, in both instances, the trends reflect the growth in productivity for all non-capital inputs.

Q. Have you calculated the recent trend in US labor PFP growth?

A. Yes. This growth trend can be easily calculated from the BLS labor productivity indexes. I believe the most relevant definition of the US economy for estimating productivity growth is the non-farm business sector. Schedule NG-LRK-Rebuttal-2 presents the calculation of the growth in non-farm business labor productivity over the 1998-2008 period, which is identical to the period used to estimate O&M PFP growth for the Northeast gas distribution industry. It can be seen that US labor productivity grew by an average of 2.71 per cent over this period.

Q. What implications does this information have for Dr. Dismukes' recommended X factor?

A. Dr. Dismukes' formula for calculating the X factor is missing one of the pieces of information necessary to calculate this X factor. The missing information is the trend in O&M PFP for the US economy. According to Dr. Dismukes' recommended formula, this trend should be subtracted from the other components that enter into the calculation of the X factor. I believe the best estimate of the US O&M PFP trend over the 1998-2008 sample period is 2.71 per cent. When this value is subtracted from Dr. Dismukes' recommended X factor of 1.12 per cent, the resulting value is -1.59 per cent (*i.e.* 1.12% - 2.71% = -1.59%). Thus, if we accept all other evidence presented by Dr. Dismukes but update his X factor formula to include the missing data, his recommended X factor becomes –1.59 per cent. This means Dr. Dismukes is actually recommending that the O&M net adjustment formula be equal to GDP-PI inflation *plus* 1.59 per cent.

Q. Do you believe it is reasonable for National Grid's O&M to be adjusted by GDP-PI inflation plus 1.59 per cent each year?

A. No. While there are other problems with Dr. Dismukes' analysis, the fact that his X factor formula yields a value of – 1.59 per cent shows that this formula is not reliable and should not be used. Instead, the formula that I recommended for computing X in Exhibit NG-LRK-1 should be employed.

X. DR. DISMUKES' O&M INPUT PRICE AND PFP MEASURES

Q. Turning to the particular values for the components of the X factor, do you agree with any of Dr. Dismukes' recommended values for these components?

A. I agree only with Dr. Dismukes' recommended value for the consumer dividend. His recommendation of 0.60 per cent for the consumer dividend is identical to mine. However, I have concerns with his industry PFP and input price measures, as well as with his recommended accumulated inefficiencies factor (AIF).

Q. What are your concerns with Dr. Dismukes' recommendations for O&M input price inflation and O&M PFP growth for the gas distribution industry?

A. I have two concerns with the methods that Dr. Dismukes used to estimate O&M input prices and O&M PFP growth for Northeast gas distributors. The first has to do with his definition of O&M costs. The second, and more important concern, pertains to aggregation bias.

Q. Please explain your first concern.

A. Dr. Dismukes' estimates of O&M PFP and input prices growth do not exclude pension costs. Certain pension and benefit costs will be excluded from the application of the Companies' net inflation mechanism, in part because these costs have historically grown at different and more variable rates than most other O&M expenses. Because of the historical volatility in these costs, National Grid and some other Massachusetts utilities are allowed to recover changes in these costs through separate reconciling mechanisms. It is not possible to isolate these specific pension and other benefit costs in O&M PFP and input price studies, because the FERC account in which they are reported contains other costs as well. Nevertheless, given the historical volatility in these pension and benefit costs, I believe historical estimates of distributors' O&M input price and PFP growth will provide a more accurate reflection of the O&M PFP trends that can be expected going forward if those historical estimates exclude all pension and benefit costs. My PFP and input price trend estimates excludes pension and benefit costs, while Dr. Dismukes' estimates do not. I believe this reduces the accuracy and precision of Dr. Dismukes' estimated PFP and input price trends for use in an O&M net inflation adjustment mechanism.

Q. Please explain your second concern.

A. My second, and most fundamental concern, pertains to aggregation bias. Controlling for aggregation bias is an important part of productivity studies. An early statement on the nature and methods for controlling for this potential problem is presented in a classic article by Jorgensen and Griliches:

> "Errors of aggregation in studies of total factor productivity have not gone unnoticed; however, these errors are frequently mislabeled as 'quality change'…To eliminate this bias it is necessary to construct the index of input or output for the group as a Divisia index of the individual items within the group. Elimination of 'quality change' in the sense of aggregation bias is essential to accurate social accounting and to measurement of changes in total factor productivity. *Separate accounts should be maintained for as many product and factor input categories as possible. An attempt should be made to exploit available detail in any empirical measurement of real product, real factor input, and total factor productivity*."[3] (italics added)

As this statement shows, it is critical to maintain "as many product and factor input categories as possible" in productivity studies, and "to exploit available detail in any empirical measurement of real product, real factor input, and total factor productivity." These measurement issues are no less important in partial factor productivity research. My study clearly used available detail on non-labor O&M

[3] Jorgensen, D.W. and Z. Griliches (1967), "The Explanation of Productivity Change," *The Review of Economic Studies*, p. 13.

input price indices and detailed O&M cost categories, since I developed detailed measures of input prices and O&M PFP for every distributor in our sample. This information was then aggregated into industry-wide O&M input price and PFP measures. I used this approach in order to control for potential aggregation bias and thereby obtain the most accurate and precise O&M input price and PFP measures that were possible given available data.

Dr. Dismukes, on the other hand, deliberately ignored the detailed data that were available and which I provided to him in response to Information Request AG-5. He claimed that such detail "is not necessary in order to develop a generalized productivity factor offset" (Exhibit AG-DED-1, at 20, line 3). Instead, Dr. Dismukes "developed an alternative model that simply uses the aggregate O&M cost and a total distribution input price index to develop an aggregate O&M input quantity and an input price index" (Exhibit AG-DED-1, at 20, lines 5-7). Dr. Dismukes' decision to ignore the available detail was motivated by what he called "the highly flawed O&M expense profile allocation" in my study. However, as explained above, my study did not allocate O&M expenses at all, and Dr. Dismukes' general description of this part of my research contains several significant errors. His overall conclusion that my approach was "highly flawed" ultimately shows that Dr. Dismukes did not recognize the importance of aggregation bias, or the need to "exploit available detail in any empirical measurement of real product, real factor input, and" productivity. Because Dr. Dismukes ignored available data and used highly aggregated O&M and input price measures, his estimates of O&M input price and PFP trends are necessarily less precise and accurate than my own.

XI. DR. DISMUKES' PROPOSED AIF

Q. Please describe Dr. Dismukes' proposal to include an accumulated inefficiencies factor (AIF) as part of the overall X factor?

A. Dr. Dismukes is proposing to resurrect the AIF, which was part of the X factor approved for Boston Gas in D.P.U. 96-50. However, the AIF was eventually removed from the X factor approved in the first BOS plan, and the Department has not incorporated an AIF in any PBR plan approved since 1997. Dr. Dismukes recommends that the X factor contain an AIF of 0.2 per cent for the first three years it is in effect. It will then be removed after those three years, which would reduce his proposed X factor from 1.12 per cent (in the first three years) to 0.92 per cent (in all subsequent years).

Q. Do you support Dr. Dismukes' proposal to implement an AIF?

A. No, I do not. I have four specific concerns with Dr. Dismukes recommendation for the AIF: 1) implementing an AIF at this time would not be compatible with the Department's original rationale for an AIF; 2) Dr. Dismukes provides no convincing evidence that can be used to evaluate the efficiency of Boston Gas and hence inform the value of an AIF; 3) relatedly, there is no sound empirical basis for Dr. Dismukes' proposal to use the AIF to move Boston Gas to industry unit cost norms; and 4) including an AIF and a consumer dividend of 0.60 per cent involves at least some degree of "double counting."

Q. Please explain why implementing an AIF for Boston Gas at this time would not be compatible with the Department's rationale for such a factor.

A. This can be seen by examining the Department's discussion of the AIF in D.P.U. 94-50, which approved a price cap plan for NYNEX-Massachusetts. It should be recognized that this is, in fact, the only example of an AIF that has ever actually been implemented in Massachusetts. In approving this factor, the Department found:

> "…it is likely that inefficiencies have accumulated and are contained in NYNEX's current rates. If the telecommunications industry has been operating less efficiently during the long-term period that is the foundation of the productivity offset than it would have under price cap regulation (a notion that must be acknowledged in order to accept price cap regulation as superior to ROR regulation in maximizing economic efficiency), then there must be accumulated inefficiencies *that should be accounted for in the first term of a price cap plan* (D.P.U. 94-50, at 175-176, italics added).

It is clear that the Department saw the AIF as relevant after the long, "accumulated" history of cost of service regulation, and before the introduction of PBR. Moreover, the Department explicitly says an AIF should be accounted for in the first term of a price cap plan. Together, these findings show that the Department logically linked the AIF to inefficiencies resulting from a legacy form of regulation and which it expected to be eliminated in the first term of an incentive-based regime. Neither of those conditions currently apply to Boston Gas, which has been subject to PBR since 1996 and is currently operating under its second comprehensive PBR plan. There is accordingly no conceptual support for Dr. Dismukes' attempt to resurrect the AIF for Boston Gas now, after the proposed termination of its second PBR plan, when the Department explicitly said the AIF was a factor to be accounted for in the first term of a price cap plan.

Q. Why has Dr. Dismukes not provided any evidence that can be used to evaluate the efficiency of Boston Gas's O&M expenses?

A. Dr. Dismukes has developed simple O&M unit cost comparisons for Boston Gas relative to other sampled distributors in the Northeast. Two unit cost measures are developed: O&M costs per customer, and O&M costs per Mcf delivered. Boston Gas's unit costs (and changes in unit costs) on these metrics are compared with those of other Northeast gas distributors, and any differences between unit costs are interpreted by Dr. Dismukes as evidence of inefficiency.

This is not an appropriate way to benchmark costs. There are a wide variety of business conditions that are beyond managerial control but can impact gas distributors' O&M costs. These factors include labor prices, population density in the territory, frost depth, the age of the infrastructure, the nature of the infrastructure (*e.g.* the extent of cast iron and bare steel main), and other factors. Any benchmarking analysis must attempt to deal with these issues in some manner. If this is not done, then differences in business conditions across distributors can be incorrectly interpreted as differences in efficiency. Dr. Dismukes analysis does not attempt to control for these other business conditions in any respect, and therefore does not satisfy the minimal standards for an acceptable regulatory application of a cost benchmarking study. Dr. Dismukes has accordingly presented no compelling evidence of the efficiency or inefficiency for any distributor in the Northeast US, and the evidence he has presented on comparative cost measures should be given no weight by the Department.

Q. Why is Dr. Dismukes' recommended AIF of 0.2 per cent not appropriate?

A. In Response to Information Request DPU-AG-1-9, Dr. Dismukes says the accumulated inefficiencies factor of 0.2 per cent is necessary for the National Grid O&M costs to converge with those of the Northeast peer group within three or four years, under the scenario where the latter costs grow at their average rate from the previous three years and the Companies' O&M costs grow at GDP-PI minus an X factor that includes an AIF. However, as discussed above, simple cost comparisons across distributors do not lead to valid inferences on their relative efficiency. It is therefore not appropriate to use simple cost comparisons as the basis for regulatory policy, unless there are controls for other business conditions that can impact distributors' costs. "Naïve" cost comparisons of the type Dr. Dismukes develops can inappropriately penalize highly efficient companies, and inappropriately reward inefficient companies. Since Dr. Dismukes does not control for a wide variety of business conditions that can drive distributors' O&M costs, his evidence on comparative costs should not be used as the basis for determining any aspect of the Companies' net inflation adjustment mechanism.

Q. Please explain why an AIF would lead to at least some double counting if the X factor also includes a consumer dividend of 0.6 per cent.

A. To evaluate the potential relationship between the consumer dividend and an AIF, it must first be recognized that my recommendation for a 0.6 per cent consumer dividend drew heavily on my experience in Ontario. In 2007-2008, I advised the Staff of the Ontario Energy Board (OEB) on the update of a set of incentive regulation plans for electricity distributors in the Province. I recommended different consumer dividends/productivity "stretch factors" for three sets of distributors, which were determined through two separate (and rigorous) benchmarking studies that PEG undertook for OEB Staff. The OEB approved consumer dividends of 0.2 per cent for the most efficient distribution "cohort," 0.4 per cent for the intermediate group of distributors, and 0.6 per cent for the least efficient group of distributors in Ontario.

The OEB's decision to differentiate consumer dividends was linked directly to studies that identified three efficiency cohorts in the industry. Thus, the 0.6 per cent consumer dividend approved for the least efficient distributors reflected an assessment of these distributors' cost inefficiencies relative to the other two cohorts. Implicitly, the Board determined that it was reasonable for the least efficient distributors to make annual efficiency improvements that were 0.2 per cent above those anticipated for firms of average efficiency (which had a consumer dividend of 0.4 per cent). Thus, the greater than average 0.6 per cent consumer dividend approved in Ontario already incorporated the OEB's assessment of the relative inefficiency of the distributors that were assigned this consumer dividend.

Based on this experience, I concluded that 0.6 per cent was the maximum consumer dividend that could be supported for National Grid's net inflation adjustment mechanism. As discussed, this 0.6 per cent consumer dividend reflected some notion of relative "accumulated" inefficiency when it was first approved in Ontario. My recommended consumer dividend did not imply that I believed National Grid was similarly inefficient, but I was aware that the Company was proposing a new incentive-based application which would apply to a different and narrower set of costs than the earlier PBR plans. There was therefore, perhaps, more uncertainty about National Grid's potential to achieve incremental O&M productivity gains than in the previous PBR update. Given this uncertainty, I believed it was warranted to recommend an aggressive but achievable consumer dividend. In my judgment, a consumer dividend of 0.6 per cent was the *maximum* level that could reasonably be recommended. One reason I believed this was the maximum reasonable dividend was that, in the Ontario context, this consumer dividend level already incorporated some assessment of the relative inefficiency of the firms to which this dividend applied. It follows that, if an AIF were layered on top of this 0.6 per cent consumer dividend, there would be at least some double counting of relative inefficiencies.

XII. SUMMARY ANALYSIS OF DR. DISMUKES' RESEARCH

Q. Please summarize your review of Dr. Dismukes alternate PFP adjustment factor.

A. With the exception of the consumer dividend, Dr. Dismukes' recommendations should be rejected. The value of Dr. Dismukes' recommended overall X factor is not consistent with his X factor formula, and any attempt to make them consistent would lead to an inappropriate X factor. Dr. Dismukes' PFP and input price estimates are also characterized by aggregation bias and therefore less precise and accurate than my recommendations. The AIF should also be rejected, since such a factor is not conceptually appropriate for National Grid at this time, is not supported by robust benchmarking studies, and incorporates at least some double counting of the potential for incremental O&M PFP gains that is reflected in 0.6 per cent consumer dividend.

Q. Does this conclude your testimony?

A. Yes, it does.

Indexing - Comprehensive

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	Pacific Gas & Electric	Bundled Power Service & Gas	1986-1989	3	Hybrid including escalation for inflation	Decision 85-12-076
CA	Pacific Gas & Electric	Bundled Power Service	1993-1995	2	Hybrid including escalation for inflation	Decision 92-12-057
CA	Pacific Gas & Electric	Bundled Power Service	1990-1992	2	Hybrid including escalation for inflation	Decision 89-12-057
CA	Pacific Gas & Electric	Power Gen, Dx & Gas	2004-2006	2	Inflation Adjustment Only. Attrition Factor is ΔCPI, with additional 1% in 2006 only.	Decision 04-05-055
CA	PacifiCorp	Bundled power service	1994-1997, extended to 1999	5	Indexing	Decision 93-12-106
CA	PacifiCorp	Electric	2007-2009, extended to 2010	3	Indexing of all expenditures except CapEx greater than $50 million	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas & Electric	Bundled Power Service	1989-1993	4	Hybrid including escalation for inflation	Decision 89-11-068
CA	San Diego Gas & Electric	Electric & Gas	1999-2002, extended to 2003	4	Indexing	Decision 99-05-030
CA	San Diego Gas & Electric	Power Gen, Dx & Gas	January 1, 2005 – December 31, 2007	2	Inflation Adjustment Only	Decision 05-03-023
CA	Sierra Pacific Power	Bundled power service	2009-2011	3	Indexing	Decision 09-10-041
CA	Southern California Edison	Electric	1997-2002	5	Indexing	Decision 96-09-092
CA	Southern California Edison	Power Gen & Dx	2002-2003	1	Indexing	Decision 02-04-055
CA	Southern California Edison	Power Gen & Dx	2004-2006	2	Hybrid including escalation for inflation	Decision 04-07-022
CA	Southern California Edison	Power Gen & Dx	2006-2008	2	Hybrid including escalation for inflation	Decision 06-05-016
CA	Southern California Gas	Gas	1986-1989	3	Hybrid including escalation for inflation	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	3	Hybrid including escalation for inflation	Decision 90-01-016
CA	Southern California Gas	Gas	1994-1996	2	Inflation Adjustment Only	Decision 94-04-088
CA	Southern California Gas	Gas	1997-2002, extended to 2003	6	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	January 1, 2005 – December 31, 2007	2	Inflation Adjustment Only	Decision 05-03-023
CA	Southwest Gas	Gas	2003-2006, extended to 2008	5	Indexing: Forecast inflation less 1% productivity	Decision 04-03-034
MA	Bay State Gas	Gas distribution	terminated in 2009	3	Indexing	Docket D.T.E. 05-27
MA	Berkshire Gas	Gas distribution	2002-2012 (no adjustments before September 2004)	7.5	Indexing	Docket D.T.E. 01-56
MA	Blackstone Gas	Gas distribution	November 1, 2004 - October 31, 2009	5	Indexing	Docket D.T.E. 04-79
MA	Boston Gas (I)	Gas distribution	December 1996 - November 2001	5	Indexing	Docket D.P.U. 96-50-C (Phase I)
MA	Boston Gas (II)	Gas distribution	November 2003 - October 2013, assuming termination in 2010	7	Indexing	Docket D.T.E. 03-40
MA	National Grid	Power Distribution	2005-2009	4	Inflation Adjustment Only: 2005-2009, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47
MA	Nstar	Power Distribution	2006-2012	7	Indexing	Docket DTE 05-85
ME	Bangor Gas	Gas Distribution	2000-2009, extended to 2012	12	Indexing	Docket 97-795
ME	Bangor Hydro Electric (I)	Power Distribution	1998-2000	2	Indexing	Docket 97-116
ME	Bangor Hydro Electric (II)	Power Distribution	June 2002 - December 2007	4.5	Indexing	Docket No. 2001-410
ME	Central Maine Power (I)	Bundled power service	1995-1999	4	Indexing	Docket 92-345 Phase II
ME	Central Maine Power (II)	Power Distribution	2000-2007	7	Indexing	Docket 99-666
ME	Central Maine Power (III)	Power Distribution	2009-2013	4	Indexing	Docket 2008-111
NY	Brooklyn Union Gas	Gas distribution	October 1, 1994 - September 30, 1997, terminated October 1, 1996	2	Rate escalation capped at change in GDP Deflator	Case 93-G-0941, Opinion 94-22
OR	PacifiCorp	Power Distribution	1998-2001	3	Indexing	Order No. 98-191
RI	Electric	Power Distribution	1997-1998	1	Indexing	Docket 2514
RI	Narragansett Electric	Power Distribution	1997-1998	1	Indexing	House Bill 8124, Substitute B3
VT	Central Vermont Public Service	Bundled power service	2009-2011	2	Indexing	Docket 7336
VT	Green Mountain Power	Bundled power service	October 1, 2010 - September 30, 2013	2	Indexing	Docket No. 7585
Alberta	Enmax	Power Distribution	2007-2016	9	Indexing	Decision 2009-035
Alberta	EPCOR	Power Distribution	2002-2005, Terminated 12/31/2003	1	Indexing	City of Edmonton Distribution Tariff Bylaw 12367
Ontario	All Ontario Distributors	Power Distribution	2000-2003, Terminated November 2002	2	Indexing	RP-1999-0034
Ontario	All Ontario Distributors	Power Distribution	2007-2010	3	Indexing	EB-2006-0089
Ontario	All Ontario Distributors	Power Distribution	2010-2013	3	Indexing	EB-2007-0673
Ontario	Enbridge Gas	Gas distribution	2008-2012	4	Indexing	EB-2007-0615
Ontario	Union Gas	Gas distribution	2001-2003	2	Indexing	RP-1999-0017
Ontario	Union Gas	Gas distribution	2008-2012	4	Indexing	EB-2007-0606

Indexing - Noncomprehensive

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	San Diego Gas & Electric	Bundled Power Service	1994-1999	5	Indexing of O&M only	Decision 94-08-023
CA	San Diego Gas & Electric	Gas	1994-1999	5	Indexing of O&M only	Decision 94-08-023
HI	Hawaiian Electric Company	Bundled Power Service	2010-2011	1	Indexing of Labor O&M only	Docket 2008-0274
HI	Hawaii Electric Light Company	Bundled Power Service	2010-2012	2	Indexing of Labor O&M only	Docket 2008-0274
HI	Maui Electric Company	Bundled Power Service	2010-2012	2	Indexing of Labor O&M only	Docket 2008-0274
VT	Vermont Gas Systems	Gas	October 1, 2006 - September 30, 2009	3	Indexing (O&M only)	Docket No. 7109
VT	Vermont Gas Systems	Gas	October 1, 2009 - September 30, 2011	2	Indexing (O&M only)	Docket No. 7537
BC	BC Gas (dba Terasen Gas)	Gas distribution	1998-2001	4	Indexing of O&M, CPCN for CapEx	Order G-85-97
BC	Fortis BC	Bundled power service	2000-2002, extended through 2003	3	Indexing of O&M, CPCN for CapEx	Order G-134-99
BC	Fortis BC	Bundled power service	2006-2009, extended through 2011	5	Indexing of O&M, CPCN for CapEx	Order G-58-06
BC	Terasen Gas	Gas	2004-2007, extended through 2009	5	Indexing of O&M, Capex via CPCNs	Order G-51-03
Ontario	Consumers Gas	Gas distribution	2000-2002	2	Indexing of O&M only	E.B.R.O. 497-01

Multiyear Cost of Service

Jurisdiction	Company Name	Services Covered	Plan Term	Plan Length	Rate Adjustment Mechanism	Case Reference
CA	Pacific Gas & Electric	Power Gen, Dx & Gas	2007-2010	4	Forecast	Decision 07-03-044
CA	PacifiCorp	Bundled Power Service	1985-1990	6	Forecast	Decision 84-07-050
CA	San Diego Gas & Electric	Bundled Power Service & Gas	1986-1988	3	Forecast	Decision 85-12-108
CA	San Diego Gas & Electric	Power Gen, Dx & Gas	2008-2011	4	Forecast	Decision 08-07-046
CA	Southern California Edison	Bundled Power Service	1986-1991	6	Forecast	Decision 85-12-076
CA	Southern California Edison	Bundled Power Service	1992-1994	3	Forecast	Decision 91-12-076
CA	Southern California Edison	Power Gen & Dx	2009-2012	4	Forecast	Docket Ap-07-11-011
CA	Southern California Gas	Gas	2008-2011	4	Forecast	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	5	Forecast	Decision 08-11-048
CT	United Illuminating	Power Distribution	January 1, 2006 - December 31, 2009 (Reopened for 2009 rate year)	4	Forecast	Docket 05-06-04
NY	Consolidated Edison	Bundled Power Service	1992-1995	4	Forecast	Opinion 92-8
NY	Consolidated Edison	Power distribution	April 1, 2005 - March 31, 2008	3	Forecast	Case 04-E-0572
NY	Consolidated Edison	Power distribution	April 1, 2010- March 31, 2013	3	Forecast	Case 09-E-0428
NY	Consolidated Edison	Gas Distribution	October 1, 1994 - September 30, 1997	3	Forecast	Case 93-G-0996, Opinion 94-21
NY	Consolidated Edison	Gas	October 1, 2007 - September 30, 2010	3	Forecast	Case 06-G-1332
NY	Long Island Lighting Company	Bundled power service	1992-1994	3	Forecast	Case 90-E-1185, Opinion 91-25
NY	Long Island Lighting Company	Gas distribution	December 1, 1993- November 30, 1996	3	Forecast	Case 93-G-0002, Opinion 93-23
NY	New York State Electric & Gas	Bundled power service	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	1	Forecast	Case 94-M-0349, Opinion 95-27
NY	New York State Electric & Gas	Gas	August 1, 1993 - July 31, 1996, Terminated in December 1995	2.5	Forecast	Case 92-G-1086, Opinion 93-22
NY	New York State Electric & Gas	Bundled power service	August 1, 1993 - July 31, 1996 (Year 3 subsequently rejected as too high)	2	Forecast	Case 92-E-1084, Opinion 93-22
NY	Niagara Mohawk	Bundled power service	July 1, 1990 - December 31, 1992	2.5	Forecast	Case 29327, Opinion 89-37
NY	Niagara Mohawk	Gas	July 1, 1990 - December 31, 1992	2.5	Forecast	Case 29327, Opinion 89-37
NY	Orange & Rockland Utilities	Bundled power service	January 1, 1991 - December 31, 1993	3	Forecast	Case 89-E-175
NY	Orange & Rockland Utilities	Power distribution	July 1, 2008 - June 30, 2011	3	Forecast	Case 07-E-0949
NY	Orange & Rockland Utilities	Gas	November 1, 2003 - October 31, 2006	3	Forecast	Case 02-G-1553
NY	Orange & Rockland Utilities	Gas	November 1, 2006 - October 31, 2009	3	Forecast	Case 05-G-1494
NY	Orange & Rockland Utilities	Gas	November 1, 2009 - October 31, 2012	3	Forecast	Case 08-G-1398
NY	Rochester Gas & Electric	Bundled power service	July 1, 1993 - June 30, 1996	3	Forecast	Case 92-E-0739, Opinion No. 93-19
NY	Rochester Gas & Electric	Gas	July 1, 1993 - June 30, 1996	3	Forecast	Case 92-G-0741, Opinion No. 93-19
NY	Brooklyn Union Gas	Gas distribution	October 1, 1991 - September 30, 1994	3	Forecast	Case 90-G-0981, Opinion 91-21
NY	Central Hudson Gas & Electric	Electric & Gas	July 1, 2006 - June 30, 2009	3	Forecast	Case 05-E-0934 & Case 05-G-0935
NY	Central Hudson Gas & Electric	Electric & Gas	July 1, 2010 - June 30, 2013	3	Forecast	Cases 09-E-0588 & 09-G-0589
OH	Cincinnati Gas & Electric	Power generation	2009-2011	3	Forecast	Case 08-920-EL-SSO
OH	Columbus Southern Power & Ohio Power	Power generation	2009-2011	3	Forecast	Case 08-917-EL-SSO, Case 08-918-EL-SSO
VT	Green Mountain Power	Bundled power service	January 1, 2007 – December 31, 2009, extended to September 30, 2010	3.75	Forecast	Docket No. 7176
Alberta	Northwestern Utilities	Bundled power service	1999-2002	4	Forecast	Decision U98060

Averages

All Plans	3.48
All Indexing Plans	3.58
All US Plans	3.45
All US Indexing Plans	3.57

Major Sector Productivity and Costs Index
Original Data Value

Series Id: PRS85006093
Duration: index, 1992 = 100
Measure: Output Per Hour
Sector: Nonfarm Business
Years: 1998 to 2008

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual
1998	107.909	108.572	110.038	110.893	109.360
1999	111.962	112.059	112.985	114.928	112.990
2000	114.499	117.087	117.104	118.258	116.827
2001	117.869	119.996	120.738	122.452	120.244
2002	125.052	125.199	126.372	126.288	125.727
2003	127.432	129.096	132.130	132.634	130.324
2004	132.922	134.132	134.354	134.636	134.013
2005	135.976	135.677	136.679	136.648	136.245
2006	137.545	137.651	137.002	137.999	137.549
2007	138.307	139.046	140.972	141.971	140.071
2008	141.782	142.821	143.200	143.994	142.933

Average growth 1998-2008	2.71%

Source:
US Bureau of Labor Statistics
Labor Productivity and Cost Indexes
http://www.bls.gov/lpc/