Patricia M. French
Lead Counsel

300 Friberg Parkway
Westborough, Massachusetts 01581
(508) 836-7394
(508) 836-7039 (facsimile)
pfrench@nisource.com

September 10, 2007

VIA ELECTRONIC FILING AND OVERNIGHT DELIVERY

Mary L. Cottrell, Secretary
Massachusetts Department of Public Utilities
One South Station, 2nd Floor
Boston, MA 02110

RE: Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources – D.P.U. 07-50

Dear Ms. Cottrell:

Enclosed for filing in the above referenced docket, please find the original and seventeen (17) copies of the Comments of Lawrence Kaufmann in response to the Order issued by the Department of Public Utilities ("Department") on June 22, 2007 and further revised on July 26, 2007 to allow for the comment filing extension. These comments are being filed jointly, on behalf of the following Massachusetts utilities:

Bay State Gas Company
The Berkshire Gas Company
Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil")
New England Gas Company
NSTAR Electric Company
NSTAR Gas Company
Western Massachusetts Electric Company

Respectfully Submitted,

cc: Jeanne L. Voveris, Esq., Hearing Officer
Jed Nosal, Esq., Office of Attorney General
Sandra Callahan, Esq. Office of Attorney General
Rachel Graham Evans, Esq., D.O.E.R.
Service List (electronic service only)

The Relationship Between Performance Based Regulation and Decoupling in Massachusetts

Comments to the Department of Public Utilities
In D.P.U. 07-50

Pacific Economics Group, LLC
Economic and Litigation Consulting

The Relationship Between Performance Based Regulation and Decoupling in Massachusetts

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September 2007

Lawrence Kaufmann, Ph.D.
Partner

PACIFIC ECONOMICS GROUP
22 East Mifflin Street, Suite 302
Capitol Square
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

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1. INTRODUCTION

In an Order issued in D.P.U. 07-50, the Department of Public Utilities (the Department, or DPU) opened an investigation into rate structures and regulatory mechanisms that may reduce incentives for the efficient deployment of demand resources in Massachusetts.[1] The centerpiece of this Order was a "strawman" proposal for decoupling a utility's allowed revenues from its energy deliveries. The purpose of this strawman was to illustrate how such decoupling adjustment mechanisms might work, focus the scope of the Department's investigation, and facilitate questions and comments from interested parties.

The Department strawman is structured so that a company's actual revenues are reconciled to allowed revenues on a regular basis. The initial allowed, or target, revenues would be determined for each company through a base rate, cost of service filing. These initial target revenues would be adjusted in following years to reflect the growth in the number of customers served. Each gas and electric utility would present an annual reconciliation filing that adjusts actual revenues per customer to target revenues per customer. This filing would also establish the next year's revenue per customer target given a projection of the number of customers to be served.

Importantly, target revenues in the strawman proposal would not be updated on the basis of performance-based regulation (PBR) or other cost recovery mechanisms. Indeed, the Order says that "(u)pon the implementation of a base rate revenue adjustment mechanism, a company's current PBR plan would no longer be in effect."[2] The Department apparently believes that the strawman, revenue decoupling mechanism can substitute entirely for the PBR approach it has encouraged for Massachusetts gas and electric utilities for more than a decade. However, the Department also requested comments on a number of aspects of its proposal, one of which was "the merits of a base rate adjustment mechanism with and without the individual elements of a PBR plan."

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[1] Department of Public Utilities, D.P.U. 07-50, *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources*, June 22, 2007

[2] D.P.U. 07-50, *op cit*, p. 18.

A coalition of Massachusetts gas and electric utilities (the Companies) asked Pacific Economics Group LLC (PEG) to provide comments to the Department on this issue.[3] PEG personnel have been involved with analyzing, designing and supporting PBR plans for Massachusetts energy utilities since 1995. We are therefore very familiar with the Department's PBR policies and objectives, as well as the State's experience with PBR. The Companies asked PEG to bring this experience to bear in considering whether decoupling mechanisms in Massachusetts should, or should not, simultaneously allow for performance-based rate adjustments.

Overall, PEG believes that any decoupling mechanism should also allow for PBR. A key reason is that the revenue decoupling strawman and the PBR mechanisms that have been approved in Massachusetts focus on two different and complementary objectives. The need for PBR is driven by long-run trends that are increasing the cost of providing gas and power distribution services, particularly in the northeastern US. The revenue strawman proposal would do nothing to mitigate these cost pressures and therefore does not substitute for PBR rate adjustments. Indeed, if decoupling is implemented without PBR, pressures on costs will likely accelerate as Massachusetts utilities are forced to file base rate applications more frequently in order to recover their costs. The Department abandoned traditional cost of service regulation in favor of PBR because, after an extensive review, it found the latter is better suited for promoting its traditional objectives of safe, reliable and least cost utility services. Eliminating PBR would therefore cause Massachusetts to revert to a less efficient regulatory system that will exacerbate upward pressures on utility costs and, ultimately, customer rates. In addition, the Department has apparently not considered the role that PBR can play in encouraging investments in enabling technologies that may facilitate efficient demand response and energy conservation. PEG therefore believes that PBR is likely to be more effective than frequent cost of service, base rate filings in promoting the Department's

[3] The coalition supporting PEG's comments includes the following companies: Bay State Gas Company, The Berkshire Gas Company, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), New England Gas Company, NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company.

traditional goals of least cost utility services as well as its increasingly important demand response and energy efficiency objectives.

PEG's comments are structured as follows. Section 2 reviews the decoupling "strawman" and the Department's objectives in the current proceeding. Section 3 addresses issues involved with integrating decoupling and PBR and briefly describes the regulatory experience in California, which has extensive experience with both decoupling and PBR. Section 4 briefly examines Massachusetts' experience with performance-based regulation. Section 5 analyzes whether the Department's traditional objectives, as well as some objectives in DPU 07-50, are more likely to be satisfied if PBR is or is not integrated with revenue decoupling. Section 6 provides concluding remarks.

2. DECOUPLING "STRAWMAN" AND DEPARTMENT OBJECTIVES

The Department writes that its investigation in D.P.U. 07-50 "…will review features of current ratemaking practices by which electric and natural gas utilities in the Commonwealth recover their prudently incurred, just and reasonable costs (including return on investment), and will consider whether and how existing mechanisms may be changed to better align companies' financial interests with the needs to (1) capture **all** available and economic system and end-use efficiencies and their associated reliability, economic and environmental benefits, and (2) foster the advancement of price-responsive demand in regional wholesale energy markets" (emphasis added).[4] It notes that, under current ratemaking practice, utilities have incentives to take actions that increase energy sales and avoid decreased sales, and these incentives may not be well aligned with public policy goals to promote end-use energy efficiency. A decoupling mechanism that breaks the link between customers' energy consumption and utilities' revenues should better align energy utilities' financial interests with broader policy objectives.

The Department's strawman decoupling proposal has three primary components. The first is a determination of allowed revenues per customer through a traditional cost of service filing. In discussing the need for such a filing, the Department says that "(i)n

[4] D.P.U. 07-50, *op cit*, p. 1.

order to determine the appropriate level of revenues per customer for a company in a way that meets the Department's statutory obligations and ratemaking precedent, the Department must understand the company's underlying revenue requirement and allocation of this revenue requirement among customer classes through an allocated cost of service study."[5] The second element is a periodic reconciliation between utilities' actual and allowed revenues. In describing this process, the Department says that "(t)his periodic reconciliation ensures that revenues would be more closely aligned with costs over time."[6] The third component is the adjustment of base rate charges to recover the revenue target. One of the critical elements of this adjustment process is that any difference between actual revenues and the target level of allowed revenues would be recovered through adjustments in base energy charges. This is apparently done for the decoupling mechanism to simultaneously achieve its two main objectives: to insulate utilities' revenues from changes in energy usage; and to give customers ongoing price-based signals to reduce their consumption.[7]

Before we discuss the relationship between decoupling and PBR, PEG offers some preliminary observations regarding the Department's decoupling objectives, particularly as manifested in the citations above. The first is the Department's recognition that regulation should be structured to encourage the realization of "…**all** available and economic system and end-use efficiencies." The Department's main goal in this proceeding is clearly to enhance end-use energy efficiency and its related environmental benefits, but it should not lose sight of the fact that other efficiencies are critical for maximizing customer benefits and achieving other policy objectives. Most importantly, customer welfare depends directly on the prices that are paid for goods and services. Effective regulation can therefore promote customer benefit by leading to lower

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[5] D.P.U. 07-50, *op cit*, p. 14.

[6] D.P.U. 07-50, *op cit*, p. 12.

[7] This is PEG's interpretation of the Department's motives and objectives expressed, for example, in the following passage: "(t)he straw proposal describes a mechanism that severs the link between electric and gas companies' revenues and sales and, instead, ties company revenues to the number of customers served. However, at the customer level, the straw proposal retains unit-based energy and demand pricing to preserve the link between customers' costs and their level of consumption"; D.P.U. 07-50, *op cit*, p.3.

energy utility prices than would otherwise be the case. A necessary condition for achieving the lowest possible utility rates (consistent with maintaining established safety, reliability and service quality standards) is for energy utilities to be operating and investing as efficiently as possible.

It is critical, therefore, not to pursue enhanced end-use efficiency as if this goal exists in a vacuum. If decoupling and the promotion of demand response is implemented in a manner that makes it more difficult for utilities to achieve other productive efficiencies, there will be upward pressures on prices. This will immediately reduce customer welfare and could have longer-term negative consequences if, for example, it reduces the competitiveness of the Massachusetts economy and causes energy price-sensitive customers to close down plants, switch operations to other States, or otherwise reduce their local economic activity. The loss of price-sensitive energy loads would reduce utilities' ability to spread their fixed costs and thereby contribute to even further upward price pressures. PEG is not trying to be overly alarmist regarding these dangers, but we also believe it is important for the Department to keep this bigger picture in mind. Social benefit will be promoted by encouraging efficiency across the entire utility value chain, which implies that regulatory policy should be balanced and comprehensive and not focus on a single objective to the exclusion, and possible frustration, of others.

Second, when discussing decoupling and PBR, it is important to distinguish between revenues and costs. Decoupling-based rate adjustments will only align actual revenues with revenue targets. Decoupling is therefore a revenue recovery mechanism, not a mechanism for recovering costs. This distinction was not sufficiently recognized in D.P.U. 07-50, particularly the statement that the "periodic reconciliation (between actual and allowed revenues) ensures that revenues would be more closely aligned with costs." Moreover, the distinction between costs and revenues can be material since, as we discuss further below, the factors that drive energy distribution costs can be largely independent of those that lead to decoupling-based revenue adjustments.[8]

[8] It is also worth noting that the Department itself distinguished between cost and revenue changes when considering issues related to revenue decoupling. Most importantly, in D.T.E. 06-77, Bay State Gas filed for an adjustment in its rates to reflect declining average use per customer (AUPC). The company petitioned for this adjustment using the exogenous cost factor in its approved PBR plan. The Department denied this request, reasoning (in part) that "(a) decline in AUPC reduces customers' aggregate demand for associated delivery service. No incremental cost has been incurred. Thus, no compensation in

Third, one implicit message in this proceeding is the need to encourage longer-term thinking. Energy conservation and enhanced demand response are objectives that may involve up-front investments and policy changes but can reap longer-term environmental benefits. The importance of longer-term thinking has also been central to PBR in Massachusetts. Indeed, the Department has preferred 10-year PBR plan terms because these were considered more conducive to longer-term planning and initiatives that can improve performance. While PEG does not advocate 10 year PBR plans for utilities in all circumstances, we do believe it is important to remember that D.P.U. 07-50 is designed to foster longer-term time horizons for utility decision-making and regulatory policy, and decoupling should not be implemented in a manner that runs counter to this longer-term focus.

Finally, one of the objectives mentioned in D.P.U. 07-50 is mitigating the volatility of energy prices. For example, the Department writes that "reductions in wholesale commodity prices or price volatility benefit all end-use customers, not only those who participate in demand resource programs."[9] Price volatility is potentially impacted by revenue decoupling, since changes in consumption under a decoupling plan give rise to revenue adjustments which, in turn, take effect through adjustments in energy utility tariffs. The way in which decoupling is implemented can therefore impact how volatile price adjustments are under the plan, and the Department should keep this criterion in mind as it evaluates decoupling alternatives.

3. INTEGRATING PBR WITH DECOUPLING

Some parties may be concerned that implementing decoupling at the same time that PBR plans are in effect may be too complex. Although this concern is never stated directly in the Order in D.P.U. 07-50, this may be part of the rationale for why the strawman did not allow for PBR rate adjustments. PEG believes that PBR can be easily

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rates is required. Exogenous cost recovery is meant to be reserved for unforeseen and unique costs that exceed a pre-determined threshold. We find a claim of lost revenues due to declining AUPC does not qualify as an exogenous cost'; D.T.E. 06-77 at 12.

[9] D.P.U. 07-50, *op cit*, p. 2

integrated with decoupling. Indeed, experience suggests that PBR and decoupling are not only compatible, but that decoupling may be more effective and durable when it is paired with PBR or other cost recovery mechanisms.

This conclusion is supported by the experience with decoupling in California. California has by far the longest and most extensive history with decoupling mechanisms of any US State. Decoupling was first implemented for Pacific Gas and Electric's (PG&E's) gas distribution operations in 1978 and for the company's electric rates in 1982. Decoupling was subsequently extended to the gas distribution operations of San Diego Gas and Electric (SDG&E), Southern California Gas and Southwest Gas, and to the electric rates of SDG&E and Southern California Edison.[10] Until very recently, California was the only State to have decoupling for both its gas and electric utilities.[11] It is therefore a relevant case study for the Department, since D.P.U. 07-50 also envisions decoupling for electric and gas utilities in Massachusetts.

California has also been a leader in PBR, and the State's energy utilities have been subject to PBR or similar mechanisms for almost the entire time that decoupling has been in effect. A wide variety of PBR mechanisms have been approved over the years, including:

- indexed price cap plans, similar to those approved in Massachusetts
- indexed revenue per customer plans (*i.e.* index based adjustments of allowed revenues per customer)
- indexed total revenue requirement plans (*i.e.* index based adjustments of overall allowed utility revenues, not just revenues per customer)

[10] It is worth noting that, on the electric side, the first decoupling plans originally applied to utilities' bundled generation, transmission and distribution operations. After industry restructuring in the 1990s, these decoupling plans applied to electric utilities' distribution operations.

[11] To the best of our knowledge, the only other State that currently has decoupling for some of its gas and electric utilities is Maryland. Decoupling has been in effect for the gas rates of Baltimore Gas and Electric since 1998 and for Washington Gas Light's gas rates in Maryland since 2005. In July 2007, decoupling plans were approved for the electric rates of Delmarva Power and Light and Potomac Electric Power in Maryland.

- pre-established allowed total revenue levels over a multi-year period, based on forward-looking revenue requirement projections;

- hybrid approaches that adjust operation and maintenance expenses using an indexing mechanism and set allowed capital expenditures based on either forward-looking projections or historical, multi-year averages for capital spending

This last, hybrid approach was commonly featured in what were known as attrition rate adjustments (ARAs). A number of ARAs were approved for energy utilities in the 1980s. The California Public Utilities Commission (CPUC) defined an ARA as a mechanism that:

> adjusts base rates in the years between general rate decisions to offset most of the effects on earnings of financial and operational attrition. Labor expenses and nonlabor maintenance and operational expenses are indexed, and a fixed amount is allowed to recover expenses related to depreciation, income taxes, financing costs, rate base growth, and other items. The ARA improves the company's ability to earn its authorized return in the years between general rate cases.[12]

While ARAs were envisioned as adjustment mechanisms between general rate cases, it is clear that the CPUC believed that this was a performance-based approach, since incentives were inherent in the regulatory lag between rate cases. The CPUC wrote that under its approach,

> …we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utilities bottom line, which means profit. In the short term, between general rate case proceedings, the shareholders benefit when the company's management can "do it for less," and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of

[12] Decision 85-12-076, California Public Utilities Commission, December 18, 1985, Appendix B, page 2.

> ratemaking, which leads us to look askance at proposals for immediate "givebacks" of all cost savings to ratepayers.[13]

The ARAs implemented more than 20 years ago were therefore forerunners, and provided a foundation, for the comprehensive PBR plans that were later approved in California.

California's history with implementing decoupling and PBR simultaneously certainly demonstrates that these ratemaking mechanisms can be compatible. In fact, unlike other States that were early decoupling pioneers, California has retained decoupling for nearly three decades (albeit with occasional interruptions, primarily because of structural changes resulting from the introduction of retail competition for electricity). This experience therefore suggests that decoupling may be more durable and effective when it is paired with PBR or other cost recovery mechanisms. A main reason (to be discussed in the following sections) is that PBR is a more efficient means for adjusting rates to recover persistent cost pressures than frequent cost of service filings.

Moreover, other elements of the California regulatory environment tend to support the stability of these regulatory mechanisms. California has a history of regular general rate case (GRC) cycles, although the length of these cycles can vary from case to case. When a GRC is conducted, a forward-looking test year is used, and adequate funding is provided for what are deemed to be the prudent, forward-looking capital expenditures reflected in that test year. The CPUC also nearly always allows for some type of "attrition" mechanism that allows for cost recovery between scheduled, GRC reviews. These regulatory procedures go beyond the details of PBR and decoupling mechanisms *per se*, but they support these objectives since, like decoupling and PBR, they create appropriate performance incentives at the same time that they give utilities a reasonable opportunity for cost recovery. California's regulatory experience, which includes the most extensive and durable commitment to revenue decoupling in the nation, therefore demonstrates that the State has abandoned the "traditional" cost of service regulatory model of GRCs at irregular intervals based on historical test years. This

[13] D. 85-03-042, p. 6.

"traditional" model is essentially reflected in the strawman proposal for setting allowed revenues per customer.

In Massachusetts, PEG believes that any transition issues associated with transforming the State's current PBR plans into decoupling plans would be minimal. The only adjustment that would be needed to the strawman itself would be that, as part of the reconciliation filing, the revenue per customer target would also be updated each year. This update would occur by applying the growth in the PBR adjustment formula (*e.g.* the growth in the GDPPI inflation factor minus the approved X factor) to the previous year's revenue per customer target. The other details of the reconciliation process would not necessarily be affected.

4. PERFORMANCE BASED REGULATION IN MASSACHUSETTS

The Order in D.P.U. 07-50 contains a long discussion of "current ratemaking practice" in Massachusetts. Nearly all of this section concerns cost of service/rate of return (COS/ROR) regulation. There is very little discussion of performance based regulation (PBR) and where PBR is addressed it is described as "variations and adjustments in the specific application of COS/ROR to individual utilities as circumstances differ across companies and across time."[14] PEG believes that the Order's discussion of PBR is incomplete and significantly understates the importance of PBR in Massachusetts utility regulation in the last dozen years. Because the Department is now considering major changes in how PBR may be implemented, PEG believes it is important to review the experience with PBR in Massachusetts. This review can help illustrate why the Department decided to implement PBR in the first place and the potential role that it can play in the future.

The Department's commitment to PBR grew out of the investigation it undertook in D.P.U. 94-158.[15] Massachusetts had some experience with incentive regulation before

[14] D.P.U. 07-50, *op cit*, p. 8.

[15] Interest in PBR was, in turn, partly motivated by an earlier investigation regarding mergers and acquisitions in D.P.U. 93-167-A; some parties in that proceeding encouraged the Department to review its

that investigation, although these were narrow incentive mechanisms targeting specific objectives such as generator performance, sharing margins on off-system and non-firm gas sales, and capacity release revenues.[16] The investigation in D.P.U. 94-158 was more comprehensive and considered the merits of broad-based versus narrow mechanisms as well as several specific incentive proposals. Twenty-eight parties filed comments in the proceeding, 27 of which supported incentive regulation and/or advocated specific incentive mechanisms.[17]

The Department noted that, while COS/ROR has been the main basis for rate regulation in the past, changing circumstances in utility industries were making this approach less appropriate. The Department stated that "…it seems unlikely that COS/ROR regulation, with its lack of flexibility and frequent, lengthy rate procedures, will continue to bring the benefits to consumers that it has in the past."[18] Moreover, the Department claimed that

> "…the defects of traditional COS/ROR regulation are well known. The "cost plus" approach under COS/ROR regulation contributes to (1) lack of incentive for cost control, through its inherent bias favoring expenditures which can be passed through to customers; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset management; (6) risk-averse management; and (7) disincentives for innovation. COS/ROR is also a costly method of regulation, and is characterized by long lags both in reflecting and controlling actual utility operations and their costs."[19]

By comparison, the Department found that "five broad classes of potential benefits are associated with incentive regulation: improved X-efficiency; improved allocative efficiency; improved dynamic efficiency; facilitation of new services; and

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existing regulatory framework and explore alternatives, including incentive regulation; see D.P.U. 94-158, *Investigation by the Department on its own motion into the Theory and Implementation of Incentive Regulation for Electric and Gas Companies under its Jurisdiction*, p. 5.

[16] D.P.U. 94-158, *op cit*, pp. 46-50.

[17] D.P.U. 94-158, *op cit*, p. 19.

[18] D.P.U. 94-158, *op cit*, p. 9.

[19] D.P.U. 94-158, *op cit*, p. 9.

reduced administrative costs."[20] X efficiency (also known as productive efficiency) refers to the ability to operate as efficiently as possible, given the available technology. The Department refers to allocative efficiency as "the ability to provide service using the optimal combination of inputs, thereby minimizing total cost."[21] This is indeed one manifestation of allocative efficiency, but another is the ability to price utility services as efficiently as possible. For example, allocatively efficient prices would not reflect cross subsidies between service classes and could be adjusted to reflect changes in customers' competitive opportunities. Dynamic efficiency refers to utilities' longer-run investment behavior and reflects efficiencies related to research, reorganization and capital equipment choices. Because it is focused on the longer run, dynamic efficiency is also related to innovation and the provision of new services. The Department noted that "(a)ll three kinds of efficiencies (*e.g.* X efficiency, allocative efficiency, and dynamic efficiency), when achieved, result in better overall value for customers."[22]

For these reasons, the Department evaluated PBR very positively vis-à-vis cost of service regulation in D.P.U. 94-158. It concluded that "(b)y giving utilities a financial stake in improved efficiency and a greater share of any of the cost savings that result, incentive regulation can create a positive incentive over COS/ROR regulation that can simultaneously deliver service to customers at lower prices, and encourage innovative services, thereby benefiting customers and firms alike."[23] The Department was careful not to proscribe or endorse any specific incentive regulation approach, although it noted that broad-based mechanisms appeared to be more appropriate and compatible with current conditions in utility industries.

Consistent with these findings, the Department has made PBR central to energy utility regulation in Massachusetts. For example, it has written that "we expect PBR proposals to be part of each electric company's next base rate case submitted to the

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[20] D.P.U. 94-158, *op cit*, p. 51-52.

[21] D.P.U. 94-158, *op cit*, p. 52.

[22] D.P.U. 94-158, *op cit*, p. 52.

[23] D.P.U. 94-158, *op cit*, p. 52.

Department, and each will be evaluated on a case-by-case basis consistent with our criteria in DPU 94-158."[24] To date, the Department has approved five PBR plans for gas distributors (for Boston Gas in 1997; Berkshire Gas in 2002; an updated Boston Gas plan in 2003; Blackstone Gas in 2004; and Bay State Gas in 2005) and two PBR plans for electric distributors (National Grid in 1999 and NStar Electric in 2005). There have been differences in the details of these PBR plans, although most have followed a similar model that included index-based rate adjustments based on the growth in an inflation factor minus an X factor.[25] Following the initial Boston Gas plan, the Department has also shown a marked preference for 10-year terms for PBR plans.[26]

Partly because of this preference for 10-year plans, the Department has not had many opportunities to review PBR plans that have expired, but the reviews that have taken place have been generally positive. The only expired energy utility PBR plan in Massachusetts has been for Boston Gas. The company submitted an updated PBR proposal in 2003 and, after an extensive review of the evidence, a new plan was approved with terms that were similar to those of the expired plan; for example, the previous plan had an X factor of 0.5%, while the X factor in the updated plan was 0.41%.

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[24] Department of Public Utilities, D.P.U. 96-100, *Investigation by the Department of Public Utilities upon its own motion commencing a Notice of Inquiry/Rulemaking, pursuant to 220 C.M.R. establishing the procedures to be followed in electric industry restructuring by electric companies subject to G.L. c. 164*, p. 116.

[25] The X factor was, in turn, comprised of three components: a productivity differential (*i.e.*, the difference between industry and economy-wide total factor productivity (TFP) trends); an inflation differential (*i.e.*, the difference between economy-wide and industry input prices); and a stretch factor or consumer dividend.

[26] The updated plan for Boston Gas featured a 10-year term, and when Bay State originally proposed a five year term for its plan the Department rejected the proposal, explaining that

"(t)he Department has considered the merits of ten-year PBR plans versus five-year PBR plans, and notes that ten-year PBR plans have certain advantages over five-year PBR plans in terms of creating an environment that allows medium and long-term efficiency planning and business decision making. In addition, ten-year PBR plans provide stronger incentives for companies to achieve efficiency gains and significant cost savings through innovation, deployment of productivity-enhancing technology, and other measures. Therefore, the Department concludes that the five-year term proposed by Bay State is not long enough to achieve the efficiencies and benefits that a PBR plan is expected to provide shareholders and ratepayers"; D.T.E. 05-27, November 30 2005, p. 399.

Part of the Department's review of Boston Gas's PBR proposal was whether the previous PBR plan created benefits for customers. Two empirical studies proved to be critical for addressing this issue. One was a comparison of the Company's operations and maintenance (O&M) cost trend before and after the PBR plan was implemented. The Department found that Boston Gas's "O&M expenses (in real 1990 dollars) increased at a much slower rate of 0.6 percent per annum, on average, between 1996-2002, compared to a 1.9 percent average annual growth rate between 1990-96, i.e. the pre-PBR period...We note that 1996 was the year the PBR plan was instituted, and we infer cause, not mere coincidence, as the basis for the change in revenues."[27] PEG also presented an econometric benchmarking model, and one of the main findings of this model was that (all else equal) the previous PBR plan reduced Boston Gas's total costs by 0.3% per annum. While the Commission ruled that there were flaws in this model (principally the "vintaging" of capital costs), it nevertheless found 0.3% to be a reasonable lower bound for the incremental productivity gains that Boston Gas had achieved in the previous PBR plan and which it could expect to achieve in its next plan. Overall, the Department found that "there is evidence that Boston Gas' operation under its former PBR plan may have contributed to constraining O&M cost growth to some extent, thus benefiting ratepayers."[28] This finding was cited when rejecting the Attorney General's call to abandon PBR for Boston Gas and, hence, was instrumental in retaining PBR for the Company. Since that time, the Department has used the Boston Gas precedent as a template and model for approving PBR plans for other Massachusetts utilities.[29]

Anecdotal evidence has also been presented that shows how PBR has impacted utilities' corporate cultures positively and led to a greater emphasis on cost-cutting. In its 2003 proposal, Boston Gas testified that it was only able to forgo a base rate increase for seven years because of its previous PBR plan, which both provided some additional revenue to reflect inflationary cost pressures and encouraged the Company to implement

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[27] D.T.E. 03-40, October 31 2003, p. 481.

[28] D.T.E. 03-40, October 31 2003, p. 471.

[29] This is most true for Bay State Gas, where there was a direct link between the approved Boston Gas plan and the terms approved for Bay State's PBR. In addition, in 2004 the Department approved a PBR settlement for Blackstone Gas with terms very similar to those approved for Boston Gas.

cost-containment and revenue-enhancement initiatives that mitigated the cost impact from inflation and capital investments needed to maintain system reliability. An example of an important cost containment initiative was the QUEST reengineering project, which led to a comprehensive reorganization and streamlining of Boston Gas operations. The Company also became part of Keyspan and realized efficiencies by purchasing a variety of services from its Service Company.[30]

In sum, Massachusetts has extensive experience with PBR and, indeed, is one of the leading PBR innovators in North America. The State's commitment to PBR followed a comprehensive examination of the merits of incentive-based and traditional COS/ROR regulation. This investigation led the Department to conclude that PBR offers many potential advantages compared with COS/ROR. The Department has since evaluated a number of PBR proposals from energy utilities and approved multiple PBR plans, most of which set utility rates for 10-year periods. In PEG's opinion, this emphasis on multi-year index-based, ratemaking mechanisms represents a significant departure from the past and is not simply "variations and adjustments in the specific application of COS/ROR to individual utilities" as intimated in the Order in D.P.U. 07-50. All available evidence also suggests that Massachusetts' PBR experience has been positive and created benefits for customers. In light of this experience, we turn now to the issue of the decoupling strawman and whether base revenue adjustment mechanisms should or should not also allow for elements of PBR plans.

5. THE NEED TO RETAIN PBR AND OTHER COST RECOVERY MECHANISMS

PEG believes it is important for PBR and other cost recovery mechanisms to be potentially integrated into decoupling revenue adjustment plans. Retaining PBR is critical for the Department to achieve its traditional goals of safe, reliable, least cost

[30] For example, see the Direct Testimony of Joseph F. Bodanza, Exhibit KEDNE/JFB-1, pp. 21-25. Bay State Gas also presented similar evidence when discussing the impact of its merger with NiSource on the Company's cost profile, including the elimination of duplicate corporate and administrative programs, greater efficiencies in operations and business processes, increased purchasing efficiencies, and the combinations of the two workforces (Direct Testimony of Stephen H. Bryant, Exhibit BSG/SHB-1, pp. 21-23). However, these efficiencies were achieved under a merger and not the type of index-based, PBR plan that was referenced in the Order in D.P.U. 07-50.

utility services most effectively. More specifically, we believe PBR should be retained in Massachusetts for the following, inter-related reasons:

- Decoupling focuses on reconciling actual revenues to target revenues, not on cost recovery

- There are long-term pressures affecting the cost of gas and power distribution services, particularly in the Northeastern US; if the Department discontinues PBR as a means for recovering these costs, Massachusetts utilities will almost certainly be forced to make more frequent cost of service, base rate filings

- Substituting frequent, base rate filings for PBR will lead Massachusetts to revert to a regulatory methodology it has previously examined and rejected; more frequent cost of service filings will almost undermine utilities' performance incentives in myriad ways that reduce their incentive to perform efficiently, increase the cost of providing service, and thereby put even greater upward pressures on utility rates

- A reversion to COS/ROR regulation would also represent a significant movement back to short-term thinking and decision-making for both regulators and utilities; this runs counter to the emphasis on longer-term planning and policy horizons in D.P.U. 07-50

- The strawman's approach for implementing rate adjustments is also likely to accentuate price volatility and is not consistent with sending efficient, price-based signals to customers

We deal with each of these points in turn.

Revenue versus Cost Recovery and Cost Pressures for Utility Industries

The Order in D.P.U. 07-50 does not properly distinguish between the factors that drive utility revenues and those that drive utility costs. In fact, the previously noted statement that "periodic reconciliation (under the strawman proposal) ensures that

revenues would be more closely aligned with costs over time" actually conflates these concepts. Decoupling mechanisms only reconcile actual to target revenues because of changes in energy consumption since the base year. There is no necessary or explicit linkage between decoupling-based revenue adjustments and changes in a utility's costs since the base year. Decoupling is therefore a revenue recovery mechanism, not a cost recovery mechanism.

This distinction is material, because nearly all the costs of power and gas distribution networks (as opposed to, say, power generation or gas supply services) are independent of customers' consumption. Of course, the strawman mechanism also includes adjustments for changes in the number of customers each year, which the Order says "is intended to ensure that revenues are closely aligned with a significant driver of costs on a company's system – the number of customers served."[31] PEG agrees that the number of customers served is a "significant" cost driver for energy delivery networks, but it does not capture all the pressures on the cost of providing energy distribution services. For example:

- Utilities have to make significant capital expenditures to replace assets that have exhausted their useful lives. Asset replacement cycles depend greatly on the age of existing assets, which naturally depends on when assets were first installed. Current capital replacement expenditures are therefore greatly influenced by *past* patterns of customer growth and the need to provide service to those customers. The magnitude of capital replacement that is required now thus has little or no correlation with current customer growth. Capital replacement expenditures for Massachusetts utilities will therefore not be appropriately compensated with a customer growth adjustment.

- The costs of many construction materials have recently been accelerating. This is due in part to higher prices for petroleum and other commodities. These costs will naturally increase as the volume of capital expenditures (*e.g.* for capital replacement) increase. But even for investments that are needed to

[31] D.P.U. 07-50, *op cit*, p. 4.

serve new customers, if there is inflation in the prices paid for construction materials, then the costs of these investment costs will grow more rapidly than the numbers of new customers served. These costs may therefore not be appropriately compensated with a customer growth adjustment.

- Other, non-growth related capital expenditures, such as for OMS and SCADA systems, also do not depend directly on changes in the number of customers served and therefore may not be appropriately compensated with a customer growth adjustment

- Employment costs (labor and pension costs) for energy utilities routinely increase at rates that exceed the overall rate of inflation. These labor price pressures will impact the costs of operational and construction workers.

Each of the factors above contributes to the fact that long-run trends in total factor productivity (TFP) growth for both power and gas distributors are well below the growth in input prices in these industries. Whenever TFP growth is less rapid than the growth in the prices paid for inputs, there will be upward pressures on (unit) costs and, hence, prices for utility services.[32] The strawman sets a fixed "target" for revenues per customer for each utility and therefore does not reflect these upward cost pressures. By contrast, the PBR mechanisms in Massachusetts are expressly calibrated to track industry changes in input prices and TFP and hence provide a measure of rate relief to reflect inflationary pressures.

It should also be noted that some of the cost pressures above are especially strong for distributors in Massachusetts. For example, Massachusetts gas distributors have some of the oldest and most cast iron and bare-steel intensive distribution systems in the nation. These conditions necessitate a greater level of capital replacement expenditures which, all else equal, will be manifested in lower TFP growth and greater upward cost pressures.

[32] PEG has provided evidence in Massachusetts that TFP growth for energy distribution networks has been growing less rapidly than industry input prices and has presented the mathematical logic showing the relationship between changes in these variables and changes in unit costs and prices; for example, see the Direct Testimony of Lawrence R. Kaufmann in D.T.E. 03-40, Exhibit KEDNE/LRK-1.

These pressures are occurring at the same time that growth opportunities (*e.g.* conversions of customers using fuel oil to natural gas) that were once instrumental in balancing cost and revenue changes are diminishing. In its previous PBR decisions, the Department has accepted that there are additional cost pressures associated with operating in the Northeastern US and found that these conditions make it appropriate to use regional industry TFP trends when setting values for X factors.[33]

Overall, PEG concludes that the strawman proposal is not designed to recover the Companies' costs appropriately. This is not surprising because revenue decoupling adjustments are, by nature, revenue recovery rather than cost recovery mechanisms. The strawman also establishes fixed revenue per customer targets that do not reflect the reality that costs are rising for gas and power distributors, particularly in the Northeast. Many of these cost pressures have little or no correlation with customers served. For these reasons, we believe the costs of even efficiently run distributors are likely to exceed the growth in revenues that are allowed under the strawman mechanism.

PBR versus Frequent Cost of Service Filings and the Implications for Performance Incentives

The reality of upward cost pressures in utility industries means that, if the decoupling mechanisms do not allow for PBR adjustments, companies would have to make more frequent applications for base rate relief. COS/ROR filings would be necessary for companies to adjust their "target" revenues per customer to reflect their increasing costs per customer. Abandoning PBR, as the strawman envisions, would therefore lead inevitably to a reversion to continual cost of service filings and the COS/ROR system the Department previously rejected.

It should also be recognized that the impact of revenue decoupling on new COS/ROR filings is likely to be more striking for electric than gas utilities. The reason is that energy consumption per customer has been trending upward for electric utilities, and downward for gas utilities, for years. All else equal, the increase in consumption per customer has been a source of revenue growth for power distributors, which has

[33] For example, see the Final Orders in D.P.U. 96-50, D.T.E. 03-40 and D.T.E. 05-27.

accordingly reduced their need for rate relief compared with gas distributors. The decoupling mechanism would remove this source of revenue growth for electric utilities, which will serve to increase their need for new base rate, COS/ROR filings.

Reverting to a less efficient, COS/ROR system can only increase cost pressures in utility industries. Recall that in D.P.U. 94-158 the Department concluded that COS/ROR had the following "well known defects": (1) the lack of incentive for cost control; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset management; (6) risk-averse management; and (7) disincentives for innovation. The Department also found that COS/ROR was a costly and administratively burdensome method of regulation. Nearly all of these defects identified by the Department are likely to be manifested if decoupling eliminates the potential for PBR adjustments and instead leads to a return to COS/ROR. Eliminating PBR would undermine the following positive objectives:

- *Incentives for cost control* PBR will promote cost control and "X efficiency" more effectively than COS/ROR since PBR formulas set allowed prices on the basis of external inflation measures and industry TFP and input price trends. The calibration of this formula creates a proxy for how prices would evolve in a competitive industry, where prices depend on industry-wide developments in input prices and TFP rather than on the costs of any individual firm. Since price changes are linked to the price cap index (PCI) rather than to a utility's own unit costs, the Company is effectively "competing" against the PCI while the plan is in effect, and any unit cost reductions it can achieve improve its bottom line. This is not the case under COS/ROR, where unit cost reductions can be translated in short order into price reductions. Setting prices on the basis of a competitive market proxy therefore creates optimal incentives to control unit cost.

- *Flexible and efficient pricing* Utilities have more ability and stronger incentives to price efficiently under PBR. PBR creates some flexibility to adjust a utility's relative prices subject to a cap on overall price inflation and to respond to

competitive market developments (*e.g.* for conversions of customers using home heating oil rather than natural gas). This type of pricing flexibility is rare in cost of service regulation, where tariffs can typically only be changed after a cumbersome regulatory review.

- *Efficient allocation of resources* PBR creates stronger incentives for allocative efficiency than under COS/ROR. Again, prices depend on external data rather than a utility's own costs and spending decisions, so utilities have incentives to pursue any and all changes in their input mix that can reduce cost. For example, managers will have optimal incentives on choosing between outsourcing or undertaking activities "in house," and maintaining vis-à-vis replacing distribution main. This is not necessarily the case under cost of service regulation. Some economists believe that input mix decisions are distorted under COS/ROR. In particular, it is argued that COS/ROR creates incentives for excessive substitution of capital for other inputs.

- *Incentives for innovation* PBR is also more likely to encourage dynamic efficiency and innovation. These incentives are notably lacking in COS/ROR for several related reasons. One is the asymmetry with which innovative practices are treated in cost of service ratemaking. Suppose a company is considering some new, untried practice that has the potential to reduce rates. Under COS/ROR, if the company pursues that practice and it is successful, then the resulting cost reductions can lead in short order to a rate hearing that transfers those gains to customers. On the other hand, if the practice does not prove to be successful, the utility is at risk of a prudence disallowance for the costs of the initiative, since it could have retained the "tried and true" approach. This asymmetry in regulatory treatment can prevent managers from implementing otherwise profitable and efficiency-enhancing programs. This regulatory asymmetry can also adversely affect the corporate culture. Since innovation leads to much lower rewards compared with competitive industries, utility managers have less incentive to look to the marketplace in order to anticipate and respond to their customers' changing needs.

PBR can encourage dynamic efficiency in several ways. First, the PBR rate adjustment formula is calibrated using comprehensive performance measures (industry TFP and input price trends). Such a PBR plan is broad-based and therefore creates *balanced* incentives to pursue all kinds of initiatives that may reduce unit cost. Second, PBR plans have multi-year terms, which increases managers' certainty that they will be able to retain the gains from innovations for a known period of time. Managers are therefore better able to evaluate programs with longer term "payback" horizons, such as those that may entail upfront costs and deliver benefits over a multi-year period. Third, the fact that rates are de-linked from costs during the PBR period dramatically reduces the role and scope of prudence reviews and may encourage the company to undertake initiatives that would be impractical under COS/ROR. All of these factors tend to create a more innovative, efficiency-focused corporate culture that can benefit customers.

- *Increased Administrative Costs* PBR costs entail far lower regulatory costs compared with cost of service regulation. The dichotomy of regulatory burdens under COS/ROR and PBR has been manifest in the PBR filings made to date in Massachusetts. The records show that far more witnesses, testimony, exhibits, and discovery have been associated with the cost of service, "cast off" rate portions than with the PBR portions of filings from Boston Gas (D.T.E. 03-40) and Bay State Gas (D.T.E. 05-27). This dichotomy is even more striking when it is recognized that the cost of service filing is associated with setting rates for a single year, while in Massachusetts the PBR filing establishes index-based rate adjustments for the next nine years. In the absence of PBR, there will naturally be additional, direct costs and administrative burdens associated with utilities' more frequent rate case filings. These incremental costs would ultimately be borne by ratepayers.

A regulatory system with the properties identified by the Department clearly reduces utilities' ability and incentives to operate efficiently. This leads naturally to higher costs. It follows that if PBR is abandoned and the Department reverts to COS/ROR, upward cost pressures in the utility industry will be exacerbated. PEG

therefore believes that decoupling in Massachusetts should allow for PBR adjustments, as well as the auxiliary cost recovery mechanisms (*e.g.* for pension and bad debt expenses) approved by the Department. These mechanisms are necessary to capture all system efficiencies and thereby promote the Department's traditional objective of least cost energy utility services.

Long-Term versus Short-Term Horizons

A return to COS/ROR regulation would also represent a significant movement back to short-term thinking and decision-making for both regulators and utilities. Companies would be making, and Department staff would be analyzing, cost of service filings on a much more frequent basis. More burdensome regulation would naturally impose direct costs but is also likely to generate less tangible negative consequences. Most importantly, the time of utility managers is a finite resource. If more frequent and burdensome regulation shifts company attention towards the regulatory process, this must necessarily come at the expense of time that could be used to improve the efficiency of utility operations or end-use energy applications. A move towards more frequent, cost of service filings can therefore impact corporate cultures in ways that reduce overall efficiency and long-run customer benefits.

An inadvertent move to short-term thinking would also run counter to the objectives in D.P.U. 07-50. Encouraging greater end-use energy efficiency and conservation is a long-term project. It also represents a fairly substantial change in how utilities do business. In this environment, overall regulatory policy should be structured to encourage forward-looking, innovative behavior, yet this is close to the opposite of the COS/ROR mentality, which is largely backward-looking and focused on recovering past costs. PEG therefore believes that the Department is more likely to achieve its objectives in D.P.U. 07-50 if it retains long-term PBR plans that properly motivate utilities.

Long-term ratemaking mechanisms will be especially important if demand response and energy conservation objectives require investments in enabling technologies. Multi-year PBR plans encourage long-term, efficiency-enhancing initiatives because, for these investments to be cost effective, companies need to retain

the investment-related efficiency gains over a period that is at least long enough to recoup their upfront costs. This is much more likely to be the case under long-term PBR plans than under the much shorter rate case cycles that will prevail in Massachusetts under a return to cost of service regulation. PEG therefore believes that the strawman proposal and the reversion to COS/ROR regulation is likely to be less effective in facilitating investments that may be needed to promote the Department's long-term energy efficiency goals than a multi-year decoupling mechanism that includes PBR rate adjustments.

Eliminating PBR now can also have a negative impact on perceived long-term regulatory stability. As these comments have shown, Massachusetts has a long commitment to PBR. Several utilities are in the middle of a multi-year PBR plan, and the proposed strawman would apparently end these plans prematurely. Financial markets clearly value regulatory stability and generally support PBR. Abandoning PBR may therefore be seen as the Department reneging on previous regulatory commitments and a source of regulatory risk, which would not be conducive to longer-term planning or attracting the capital needed to undertake long-lived investments.

Price Volatility

The Order in D.P.U. 07-50 says reduced price volatility is desirable, but the strawman proposal may accentuate price volatility in two ways. One is that if PBR is abandoned, companies would revert to cost of service filings at frequent but (in all likelihood) less than annual intervals. When rates are adjusted under COS/ROR, they are likely to lead to larger price shocks than would be the case under the more gradual rate adjustments that occur under PBR. Larger but less frequent price changes would represent a source of price volatility.

The strawman recommendation of adjusting revenues via changes in volumetric charges will also increase price volatility. Over time, this approach will increase the share of distributors' revenues that are collected through energy base rate charges. This will make distributors' actual revenues more rather than less dependent on their customers' consumption. Although there will be annual reconciliations between actual and allowed revenues, the magnitudes of these reconciliations will necessarily become

more variable when larger shares of utility revenues are collected through volumetric-based charges. Greater variability in reconciled revenues necessarily translates into more price volatility, which will negatively impact customer welfare and undermine one of the Department's goals in this proceeding.

PEG believes a better approach may be to collect reconciliation revenues through adjustments in the customer charge. This would clearly reduce revenue and price volatility. It would also move distributors' rate designs in the direction of known cost causality, since more distribution costs are driven by changes in customer numbers than changes in delivery volumes. This would also, in fact, be more consistent with good ratemaking principles and would lead to more efficient pricing structures and send appropriate demand management price signals to customers. Ultimately, efficient demand management is encouraged as rate design moves in the direction of long-run incremental costs (in principle including an adjustment for environmental externalities).

6. CONCLUSION

The Department has opened an important investigation into facilitating the efficient deployment of demand resources in Massachusetts. The centerpiece of the Department's Order in the proceeding is a strawman proposal for decoupling a utility's allowed revenues from its energy deliveries. This strawman has effectively illustrated the basics of how decoupling adjustment mechanisms might work and should focus the scope of the Department's review into these matters.

One important issue raised in the Order is whether decoupling mechanisms should also allow for PBR rate adjustments. PEG strongly believes that this should be the case. PBR mechanisms are needed because of long-run trends that are increasing the cost of gas and power distribution services, particularly in the northeastern US. Many of these costs are independent of changes in customer numbers and changes in delivery volumes. The revenue strawman proposal would therefore do nothing to mitigate these cost pressures and does not substitute for PBR rate adjustments. Indeed, if decoupling is implemented without PBR, Massachusetts utilities will almost certainly file base rate

applications more frequently in order to recover their costs. The Department has found PBR to be a more effective regulatory system that COS/ROR regulation, so eliminating PBR would cause Massachusetts to revert to less efficient regulatory arrangements that will exacerbate upward pressures on utility costs and, ultimately, customer rates. In addition, the Department has apparently not considered the role that PBR can play in encouraging investments in enabling technologies that may facilitate efficient demand response and energy conservation. PEG therefore believes that PBR is likely to be more effective than frequent cost of service, base rate filings in promoting the Department's traditional goals of least cost utility services as well as its increasingly important demand response and energy efficiency objectives, and we recommend that it be retained.