PRE-FILED JOINT DIRECT TESTIMONY

OF

NICHOLAS A. CROWLEY, CFA
DANIEL MCLEOD, Ph.D.

Total Factor Productivity Study,

Cost Benchmarking Study,

and

Performance-Based Regulation Framework Evaluation

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NICHOLAS A. CROWLEY, CFA AND DANIEL P. MCLEOD, Ph.D

I. Introduction

Q. Mr. Crowley, please state your full name and business address.

A. My name is Nicholas A. Crowley. My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

Q. Mr. Crowley, by whom are you employed and in what capacity?

A. I am a Vice President with Christensen Associates Energy Consulting ("CA Energy Consulting").

Q. Please summarize your educational background and business experience.

A. I have a Bachelor of Science degree in Economics, as well as a Master of Science degree in Economics from the University of Wisconsin-Madison. I began working at CA Energy Consulting in 2016. Prior to joining this firm, I was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission ("FERC"), where I assisted with energy industry benchmarking, the indexed regulation of oil pipeline rates,[1] and the review and evaluation of natural gas pipeline rate cases. In these roles, I have worked extensively with FERC data, and other federal data, for cost benchmarking analysis of the electric and gas utility sector and in measuring industry Total Factor Productivity ("TFP") for filings before regulatory authorities in the United States and Canada. I have authored articles in *The Electricity Journal* and *Utilities Policy* related to the rate regulation

[1] Five-Year Review of the Oil Pipeline Index. Issued: December 17, 2015. 153 FERC ¶ 61,312.

of utilities. I also hold the professional designation of Chartered Financial Analyst ("CFA") awarded by the CFA Institute and the professional designation of Certified Rate of Return Analyst awarded by the Society of Utility and Regulatory Financial Analysts. My curriculum vitae is attached as Exhibit NG-CAEC-3.

Q. Mr. Crowley, have you previously testified before the Department of Public Utilities?

A. Yes. I filed testimony with the Department of Public Utilities (the "Department") on behalf of Massachusetts Electric Company d/b/a National Grid in D.P.U. 23-150. In addition, I have filed testimony on behalf of Fitchburg Gas & Electric Company, d/b/a Unitil in D.P.U. 23-80 and D.P.U. 23-81, providing expertise on industry TFP growth and benchmarking as a component in the company's performance-based regulation ("PBR") rate application. I also testified about TFP growth with my colleague Dr. Mark Meitzen on behalf of NSTAR Electric Company d/b/a Eversource Energy in D.P.U. 22-22; and on behalf of Boston Gas Company and the former Colonial Gas Company ("former Colonial Gas") each d/b/a National Grid in D.P.U. 20-120. I also calculated TFP growth rates for the electricity sector and developed indexes for use in PBR in proceedings before the Department on behalf of the Company in D.P.U. 18-150 and on behalf of NSTAR Electric in D.P.U. 17-05. I also assisted in the allocated cost-of-service study performed by CA Energy Consulting for NSTAR Electric in D.P.U. 22-22.

Q. Dr. McLeod, by whom are you employed and in what capacity?

A. I am a Senior Economist with CA Energy Consulting.

Q. Please summarize your educational background and business experience.

A. I have a Bachelor of Arts degree and a Master of Science degree in Economics from the University of Wisconsin-Madison. I also received my Ph.D. in Economics from the University of Wisconsin-Madison. I began working at CA Energy Consulting in 2021. My research and consulting experience span several network industries, including airlines, electricity, gas, oil pipelines, postal, and railroads. My work in these industries has involved incentive regulation, productivity and cost measurement, and pricing. In rate proceedings involving PBR, I have sponsored testimony, performed industry productivity and cost benchmarking analyses, and quantified potential financial remedies as part of a reopener during a PBR term. I have also co-authored technical reports on PBR. My curriculum vitae is attached as Exhibit NG-CAEC-4.

Q. Dr. McLeod, have you previously testified before the Department or other state regulatory commissions?

A. I have not previously testified before the Department. However, I recently testified with Mr. Crowley on behalf of the New Hampshire Department of Energy to evaluate the PBR framework proposed by the Public Service Company of New Hampshire d/b/a Eversource Energy, in Docket No. DE 24-070.

II. <u>Purpose of Testimony</u>

Q. On whose behalf are you jointly submitting this testimony?

A. In this proceeding, we are testifying on behalf of Boston Gas Company ("Boston Gas," or the "Company"), a subsidiary of National Grid USA.

Q. What is the purpose of your testimony?

A. Our testimony addresses the following topics: (1) the theory and practice of PBR, with a focus on the Department's regulatory objectives and precedent; (2) an evaluation of the elements of Boston Gas's proposed PBR framework; (3) an analysis of gas distribution industry TFP growth for the purpose of calibrating the Company's proposed revenue cap; and (4) a cost benchmarking study for the operations of Boston Gas, which informs the recommendation of a consumer dividend. A comprehensive description of the proposed second-generation PBR framework can be found in the Company's PBR Panel testimony (Exhibit NG-PBRP-1).

Q. How is this testimony organized?

A. Our testimony is organized as follows:

Section I	Introduces the witnesses.
Section II	Provides the purpose and organization of our testimony.
Section III	Provides a brief overview of the theory and practice of PBR.
Section IV	Outlines the Department's applicable regulatory objectives.
Section V	Explains the interaction of the PBR framework with the revenue cap.
Section VI	Presents the findings of the industry TFP growth study.
Section VII	Presents the cost benchmarking analysis and consumer dividend.
Section VIII	Evaluates the Company's PBR proposal.
Section IX	Offers conclusions.

Q. Are you presenting any exhibits that accompany your testimony in this case?

A. Yes. We are presenting the following exhibits with our testimony:

- Exhibit NG-CAEC-2 (Confidential) – TFP Growth Study

- Exhibit NG-CAEC-3 – Crowley Curriculum Vitae
- Exhibit NG-CAEC-4 – McLeod Curriculum Vitae

III. <u>Overview of the Theory and Practice of PBR</u>

A. Current State of Utility Performance-Based Regulation

Q. What is the definition of Performance-Based Regulation?

A. Performance-based regulation (also known as performance-based ratemaking or incentive regulation) is an approach to regulating utilities that emphasizes the achievement of outcomes that benefit ratepayers and utilities through financial incentives. PBR may create incentives for cost efficiency, a reduced regulatory burden, or enhanced service quality. A PBR framework may provide specific financial incentives for the achievement of any number of policy objectives.

PBR is an umbrella term that refers to a suite of tools that lie along a spectrum of incentive strength. The two primary groups of PBR tools are Multi-Year Rate Plans ("MYRPs") and targeted performance incentive mechanisms ("PIMs"). In general, MYRPs are focused on input efficiency: the aim is to incentivize the utility to produce its outputs using the least-cost combination of inputs like capital, labor, and materials. An indexed cap is a form of MYRP defined by CA Energy Consulting as a framework that sets rates according to a formula using index numbers unrelated to the particular utility's performance, like industry inflation and productivity growth. Indexed caps, as a category, include both price caps and revenue caps. PIMs, on the other hand, focus on output efficiency. These two sets of tools can be used together.

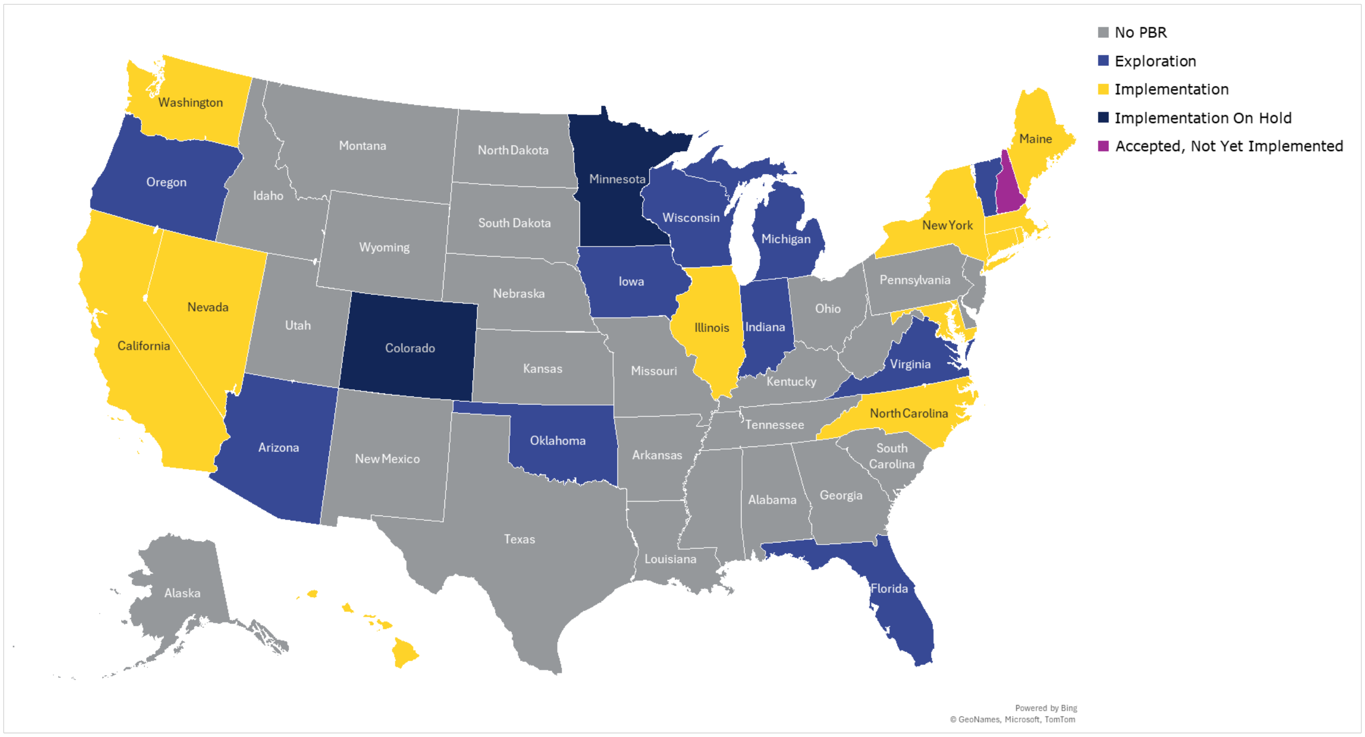
The term PBR generally does not include certain alternative regulation tools, like formula rate plans, which exist in jurisdictions including Louisiana, Mississippi, and Arkansas.

Q. Where are PBR frameworks currently in place in the United States?

A. Broadly defined to encompass both MYRPs and PIMs, our review indicates that 11 U.S. states contain utilities operating under some form of PBR. Many other states are currently exploring the adoption of PBR. For example, in July 2025, the New Hampshire Public Utilities Commission accepted a proposal by Public Service Company of New Hampshire d/b/a Eversource Energy, to operate under a four-year revenue cap plan. Other states, including Oregon and Virginia, have open dockets to consider how to implement PBR tools. In 2023, the National Conference of State Legislatures published a report suggesting that legislative bodies throughout the U.S. consider PBR as an approach to utility regulation.[2] Figure 1, below, illustrates the adoption and exploration of PBR in this country.

[2] "Performance Based Regulation: Harmonizing Electric Utility Priorities and State Policy," by Daniel Shea, *National Conference of State Legislatures,* April 2023.

Figure 1: Status of PBR Across United States[3]



Q. What is the status of PBR as a means of regulating utilities in other countries?

A. PBR frameworks are common outside of the United States, in Canada, Europe, Australia, and New Zealand. In Canada, regulatory authorities in British Columbia, Alberta, and Ontario regulate their gas and electric distributors under either price caps or revenue caps.[4] Of the 35 European nations surveyed by the Council of European Energy Regulators, all but one regulated its gas or electric distribution utilities with some form of incentive

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[3] Data for this figure from "Tracking State Developments of Performance-Based Regulation," by National Association of Regulatory Utility Commissioners, April 2024. It has been modified to include other PBR developments CA Energy Consulting is currently aware of.

[4] Indexed price caps adjust customer rates directly. Indexed revenue caps adjust the allowed revenue amount, and customers rates are then adjusted accordingly to provide the allowed revenue.

regulation.[5] Our review of indexed cap (revenue and price cap) PBR plans in North America, Australia, and Europe reveals that the details of PBR frameworks differ across jurisdictions, but most utilities in these jurisdictions operate under some form of indexed adjustment to either rates or allowed revenues.

B. Indexed Cap PBR: Price Caps and Revenue Caps

Q. What is the motivation and history behind indexed cap PBR?

A. As stated above, the general definition of an indexed cap is a framework that adjusts rates or revenues according to a formula using index numbers unrelated to the utility's own performance, like inflation and industry productivity growth. A form of indexed cap, a price cap, was introduced in Great Britain to regulate the country's telecommunications industry in the 1980s and was subsequently adopted to regulate gas and electric distribution utilities. When North American electricity markets were restructured in the 1990s, certain jurisdictions like Ontario, California, and Massachusetts adopted indexed cap frameworks to regulate gas and electric utilities. Since then, more states and provinces have adopted indexed cap PBR, not only among electric and gas utilities, but also in other industries. Oil pipelines in the United States operate under a price index approach, as does the U.S. Postal Service.

The motivation behind indexed cap PBR is to introduce competitive market pressures to the utility to promote cost efficiency. In the short run, customers benefit from rate stability

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[5] See "Regulatory Frameworks for European Energy Networks," Council of European Energy Regulators, February 3, 2025.

in the form of rate growth constrained to the industry average. In the long run, customers benefit from slower rate growth compared to traditional regulation, all else equal. An additional benefit of PBR is a streamlined regulatory process that reduces the need for frequent rate cases.[6]

A well-designed PBR framework provides an enhanced incentive to find ways to reduce costs through the elimination of inefficiencies that might have otherwise persisted if the utility had continued to operate in a traditional, cost of service regulatory environment, not subject to a stay-out period. In principle, these incentives and a longer time period between regulatory proceedings can be expected to lead to more efficient utility behavior, efficiency in the regulatory process, and benefits for all stakeholders, including customers of the regulated utility, as discussed more below.

Q. Is the Company proposing an indexed cap consistent with established frameworks?

A. Generally, yes. The Company is proposing a total revenue cap that aligns with economic theory and precedent. However, as noted in the PBR Panel's pre-filed direct testimony, Boston Gas has elected not to include a growth, or *G*, factor in its proposed PBR formula. This decision was made in recognition of the Department's directive to replace the current per customer revenue decoupling mechanism with a total revenue cap decoupling mechanism, to align with the Commonwealth's greenhouse gas emission reduction

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[6] PBR offers greater efficiency in the operation of the regulatory process by extending the period of time between costly and administratively burdensome rate cases. A utility may have two rate cases over a ten-year period (as the Company is proposing here), while a comparable utility could have as many as five over the same time period, depending on the jurisdictional ratemaking process.

policies. If customer growth continues to increase as forecasted during the PBR term, the PBR formula will not provide corresponding adjustments to total revenue, and the Company will need to identify cost efficiencies beyond the industry average productivity growth to offset any incremental cost associated with customer growth to mitigate earnings attrition.

C. Results of Indexed Cap PBR

Q. Are there studies or other evidence that demonstrate that indexed PBR provides value to customers?

A. Studies published in academic literature indicate that PBR frameworks tend to improve utility cost efficiency. For example, a study of electric distribution utilities found productivity growth (about one percent per year) in Great Britain's electric distribution sector over a 29-year period from 1990 to 2019, and attributed this productivity growth, in part, to the nation's PBR framework.[7] Another study drew similar conclusions by contrasting productivity improvement from 1985 to 1998 in the UK with the smaller relative productivity growth in Japanese electric distribution sector during the same period.[8] A study using data from Ontario and Alberta, Canada found that distribution utility customers experienced slower rate escalation under price caps and revenue caps

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[7] Victor Ajayi, Karim Anaya, Michael Pollitt. *Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain. The Productivity Institute Working Paper No. 012.* November 2021.

[8] Toru Hattori, Tooraj Jamasb, Michael Pollitt. *Electricity Distribution in the UK and Japan: A Comparative Efficiency Analysis 1984-1998. The Energy Journal*, *26*(2). 2005. p. 23-47.

relative to a peer set of utilities operating under "traditional" regulation in the United States.[9]

Q. Are there similar studies that evaluated PBR in Massachusetts?

A. To our knowledge, no academic studies have evaluated the effect of revenue caps on customer rates in Massachusetts specifically. Studies that evaluate the efficacy of regulatory frameworks require cost data from many companies operating consistently under a PBR framework for more than a decade, including a set of comparator companies, in order to estimate the effect of policy on rates. The time span that utilities have operated under PBR in Massachusetts has been too short to draw statistically significant conclusions about the effect of revenue caps in the state. However, the cost benchmarking analysis, discussed below, suggests that Boston Gas has improved its cost control on operations and maintenance ("O&M") expenditures since it began operating under a revenue cap in 2021. Furthermore, the price growth faced by Boston Gas's customers, as measured by average revenue per customer, slowed relative to both the Northeast sample and a broader National sample since the introduction of PBR. This occurred while Boston Gas operated under a revenue per customer revenue decoupling mechanism approved in D.P.U. 20-120.

[9] Crowley, Nicholas, and Mark Meitzen. "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." *Utilities Policy.* Volume 72, October 2021.

Q. What have regulators in other jurisdictions found about their experience with indexed cap PBR?

A. Some regulators that operate under PBR have provided commentary on the results of PBR. The Alberta Utilities Commission ("AUC") published an evaluation of PBR, which included a survey of stakeholders to determine whether the PBR framework was achieving its original goals. The AUC concluded that PBR was effective in achieving the goals of promoting efficiency incentives and that the utilities did not compromise – service quality to achieve these efficiencies.[10] In 2023, the Australian Energy Regulator ("AER") conducted a review of its incentive schemes applied to distribution and transmission utilities,[11] concluding that the existing Efficiency Benefits Sharing Scheme and Capital Expenditure Sharing Scheme reduced operating and capital expenditures.[12] In Great Britain, Ofgem stated that RPI-X regulation delivered a 50 percent reduction in electricity distribution costs between 1990 and 2008, *in real terms*, as well as improved quality of service in the form of a reduced number and duration of outages.[13]

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[10] Alberta Utilities Commission. *Evaluation of Performance-Based Regulation in Alberta.* June 30, 2021.

[11] Australian Energy Regulator. *Review of incentives schemes for networks. Final Decision.* April 2023.

[12] Australian utilities operate under a 5-year forecasted revenue cap. The Efficiency Benefits Sharing Scheme is an Efficiency Carryover Mechanism that rewards utilities for reducing their operating expenses below forecasted costs, and the Capital Expenditure Sharing Scheme rewards utilities for reducing their capital expenditures.

[13] Ofgem. *Electricity Distribution Price Control Review Initial Consultation Document.* March 28, 2008.

IV. Massachusetts Department of Public Utilities Regulatory Objectives

Q. What is the precedent in Massachusetts for utilities to operate under PBR?

A. The Department has accepted PBR frameworks filed over the course of several decades in Massachusetts. The foundational proceeding on incentive regulation in Massachusetts was D.P.U. 94-158, which investigated the theory and implementation of incentive regulation for electric and gas utilities. Since that time, numerous docketed proceedings have taken place at the Department related to PBR, providing a sound foundation for Boston Gas's current PBR filing. The Department has issued eight decisions since 2017 approving PBR frameworks for the three gas and electric distribution utilities in the state (see Table 1).

Q. What did the Department investigate in D.P.U. 94-158?

A. The impetus for D.P.U. 94-158 was that the Department sought to investigate alternatives to traditional cost of service regulation, which the Department recognized as deficient:

> "…the defects of traditional [cost-of-service/rate-of-return ("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 performance; (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."[14]

In that proceeding, the Department examined the criteria by which PBR proposals for electric and gas distribution companies would be evaluated. The Department found that

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[14] D.P.U. 94-158, at 9.

because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review process, which requires that rates be just and reasonable.[15] Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is likely to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation.[16] Lastly, the Department stated that a well-designed incentive framework should provide utilities with greater incentives to reduce costs than those under traditional cost of service regulation and should result in superior benefits to customers.[17]

Q. Please describe the key findings from D.P.U. 94-158.

A. The Department found that "incentive regulation has the potential to bring real efficiency gains and reduced rates to consumers."[18] In addition, the Department established a number of factors it would weigh in evaluating incentive proposals.[19] These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not

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15 D.P.U. 94-158, at 52.

16 D.P.U. 94-158, at 57.

17 D.P.U. 94-158, at 57.

18 D.P.U. 94-158, at 41.

19 D.P.U. 94-158, at 57.

result in reductions of safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. These objectives mesh with the guiding principles of PBR established in other jurisdictions.[20]

Q. What are the expected benefits associated with PBR outlined in the Department's D.P.U. 94-158 decision?

A. In D.P.U. 94-158, the Department described five different benefits that PBR might provide, as follows.[21]

- Improved X-efficiency: the degree to which a firm maximizes the production of goods and services that are produced with any given combination of inputs. If a firm does not operate with maximum X-efficiency, the firm and society lose the potential benefits of increased output at no additional cost.
- Allocative efficiency: the ability to provide service using the optimal combination of inputs, thereby minimizing total cost.
- Dynamic efficiency: improved ability of firms to create value with given resources, resulting from innovation, including making cost-reducing investments in areas such as research, reorganization and capital equipment that result in the provision of service at the lowest possible cost over time.

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[20] See, e.g., Alberta Utilities Commission, "Regulated Rate Initiative – PBR Principles," AUC Bulletin 2010-20, July 15, 2010. See also British Columbia Utility Commission, *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, Decision and Orders G-165-20 and G-166-20, June 22, 2020, p. 168.

[21] D.P.U. 94-158, at 53.

- Facilitation of new services: incentive regulation should create a positive incentive to deliver service to customers at lower prices and encourage innovative services, thereby benefiting customers and firms alike.
- Reduced administrative and regulatory costs: cost reductions can be achieved through longer ratemaking cycles and lower litigation costs.

Q. Has the Department's criteria for evaluating PBR frameworks changed since issuing its D.P.U. 94-158 decision?

A. Since the Department's decision in D.P.U. 94-158, PBR has expanded across North America, providing opportunities to gain insight into the mechanics and potential pitfalls of price and revenue caps. The Department has also gained substantial firsthand experience regulating utilities under PBR, particularly over the past decade. The Department has not changed its criteria for evaluating PBR proposals, as outlined above, nor has the Department altered its expectations for the benefits that PBR might provide. However, the Department has since explicitly recognized the need for certain specific plan components to be included in PBR frameworks in order for the plans to be successful. For example, the Department has found that exogenous factors are necessary to protect the regulated utility from large, unexpected costs that are outside of management's control. In addition, the Department has found that separate cost recovery mechanisms, like the Gas Safety Enhancement Plans ("GSEP"), may be necessary to ensure that the utility is able to recover the costs of statutorily mandated capital investment. These decisions align with decisions made by regulatory authorities in other jurisdictions.[22]

Q. What are the characteristics of the PBR frameworks recently approved by the Department for other utilities in Massachusetts?

A. Since 2017, the Department has approved utility PBR frameworks in eight proceedings, as follows:

- NSTAR Electric d/b/a Eversource Energy (D.P.U. 17-05);
- Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid (D.P.U. 18-150);
- NSTAR Gas Company d/b/a Eversource Energy (D.P.U. 19-120);
- Boston Gas Company d/b/a National Grid (D.P.U. 20-120);
- NSTAR Electric d/b/a Eversource Energy (D.P.U. 22-22);
- Fitchburg Gas & Electric Company d/b/a Unitil (D.P.U. 23-80 and D.P.U. 23-81); and
- Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (D.P.U. 23-150).

Each of these proceedings set revenue caps that adjust allowed revenues, or a portion of allowed revenues, using an annual formula based on inflation and productivity (often called "*I-X*"). In each case, the updated revenue cap value becomes the target revenue collected through the existing revenue decoupling mechanism. As part of these decisions, the Department also approved additional PBR components for each framework, including exogenous factors, Earnings Sharing Mechanism ("ESM"), and consumer dividends.

[22] For example, in Hawaii, utilities operating under the revenue cap have the opportunity to recover project costs through an "Exceptional Projects Recovery Mechanism." In Alberta and Ontario, distribution utilities can file for cost tracker treatment for certain eligible projects. In British Columbia, FortisBC is permitted to file for Z factor treatment of storm costs, and a portion of capital costs are recovered outside the revenue cap.

Table 1, below, summarizes the key outcomes of each decision by the Department. In all cases, the Department accepted an exogenous factor, as well as an ESM that shares with customers up to 75 percent of earnings above a specified deadband.[23] Note that the zero X factors correspond with regulatory agreements for a capital supplement known as K-bar. Also, the positive X factor under D.P.U. 23-150, adjusts revenue associated only with O&M costs, and is therefore not directly comparable to the other revenue cap X factors in the table, which apply to total revenues.

Table 1: Summary of Recent Massachusetts PBR Frameworks

Decision	Distribution Service	Term (Years)	X Factor	Consumer Dividend (bps)	Additional Total Capital Supplement[1]
D.P.U. 17-05	Electricity	5	-1.56%	25	None
D.P.U. 18-150	Electricity	5	-1.72%	40	None
D.P.U. 19-120	Natural Gas	10	-1.18%	15	None
D.P.U. 20-120	Natural Gas	5	-1.30%	30	None
D.P.U. 22-22	Electricity	5	0.00%	25	K-bar
D.P.U. 23-80	Electricity	5	0.00%	25	K-bar
D.P.U. 23-81	Natural Gas	5	0.00%	25	None
D.P.U. 23-150	Electricity	5	+0.21%	40	ISRE[2]

Note 1: All gas utilities in Massachusetts have a statutory obligation to replace leak-prone pipe, and the companies recover this capital replacement through the GSEP cost recovery mechanism.

Note 2: The Infrastructure, Safety, Reliability and Electrification ("ISRE") provision provides for the recovery of incremental costs associated with the Company's implementation and deployment of National Grid's Core electricity distribution capital investments. The PBR framework covered only O&M costs, which gives rise to a different X factor.

[23] NSTAR Gas (D.P.U. 19-120) has a tiered ESM for its 10-year plan, in which profits 150 bps above the allowed return on equity ("ROE") are shared 50/50, and profits 200 bps above the allowed ROE are shared 75/25.

Q. Did the Department allow companies to recover costs of certain capital projects in addition to the PBR mechanism?

A. Yes. One of the current challenges for Massachusetts utilities, as well as for both gas and electric utilities across the continent, is the need to replace aging capital with substantial investments in new plant. A gas pipeline replacement program known as GSEP has provided revenue recovery to gas distribution companies in Massachusetts for costs outside of the revenue requirement as adjusted by the *I-X* formula. The Department has found PBR frameworks must consider accommodations for these investments.[24] Regarding the inclusion of GSEP alongside the revenue cap formula, the Department found in D.P.U. 19-120 that, "[t]he PBRM, unlike the GSEP, is not a recovery mechanism, and therefore "double recovery" is not a concern."[25] The PBR formula (i.e., $I - X + G$) provides revenue growth sufficient for a utility that has a percentage of leak-prone pipe in line with peer companies. Mechanisms that allow for revenue growth beyond the PBR formula allow Massachusetts companies to replace or repair leak-prone pipe necessary for safety and reliability, and converge with the industry average.

For electric distribution utilities, recent capital investment has taken the form of grid modernization. In decisions under D.P.U. 22-22 and D.P.U. 23-80/81, the Department

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[24] For example, in D.P.U. 22-22, the Department stated that:

> "[Eversource] will need significant capital investments to develop a dynamic and modern distribution network. The Department anticipates that the Company may identify several capital projects to achieve these objectives during the development of its electric sector modernization plans pursuant to G.L. c. 164, D.P.U. 22-22 Page 61§ 92B. The Department recognizes that required investments will go beyond the Company's grid modernization proposals approved in Second Grid Modernization Plans."

[25] D.P.U. 19-120, at 95.

approved K-bar, a capital recovery mechanism, which adjusts allowed revenues beyond the *I-X* formula and allows for the recovery of spending associated with grid modernization programs.

These Department decisions demonstrate an understanding that the *I-X* formula is not a cost recovery program for particular major projects, but rather a revenue adjustment mechanism to adjust base revenues over the extended rate stay-out period of the PBR term.

Q. Please summarize your understanding of the Department precedent on PBR since D.P.U. 94-158.

A. Through the eight decisions summarized in Table 1, the Department has demonstrated an understanding that in order for a PBR framework to properly balance incentives with achievability, a PBR framework must be tailored to the particular regulated utility. The Department has found that just as no two utilities are identical, PBR frameworks differ from utility to utility. This aligns with the perspective of regulators across North America. For example, the Alberta Utilities Commission listed as one of its guiding principles of PBR that "a PBR plan should recognize the unique circumstances of each regulated firm."[26] In Ontario, where dozens of electric distribution utilities operate under PBR, each firm can elect one of several options from a menu of different PBR approaches, allowing each firm to determine its own unique plan.[27] The Department's recognition that PBR is not a one-size-fits-all regulatory solution is relevant in light of the recent capital replacement cycle

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26 AUC Decision 2012-237, September 12, 2012, at 7.

27 "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," *Ontario Energy Board,* October 18, 2012, at 13.

among gas distributors in Massachusetts and will continue to be relevant as industry changes occur in light of the energy transition.

The Department's decisions in recent years have recognized that PBR frameworks may evolve as business conditions change over time. When the term for an established PBR plan ends, stakeholders should once again engage the question of how best to continue under PBR, or even whether PBR should continue. The Department's recent decision in D.P.U. 23-150 provides an example of how it has re-evaluated the components of a utility's plan between PBR generations. Specifically, the Department deviated from prior decisions by allowing Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid to bifurcate its capital and O&M-related revenue, setting capital according to an annual review process and setting O&M with a revenue cap formula. This decision demonstrates an understanding that a PBR framework is not immutable—rather, it can be adjusted and improved over time. Again, this idea aligns with the practice of PBR in other jurisdictions. PBR frameworks in British Columbia, Alberta, Ontario, and Great Britain have evolved substantially over time as the industry has changed and as stakeholders learned which incentive mechanisms work well and which do not.[28]

As discussed in Section III, PBR frameworks differ across jurisdictions and over time. In all cases, however, PBR aims to improve upon traditional regulation with incentives that

[28] In fact, FortisBC in British Columbia also bifurcated its capital- and O&M-related revenues, with capital recovered according to a forecast and O&M recovered under an I-X formula during its five-year PBR term. In Great Britain, utilities transitioned from an I-X price cap to hybrid forecast and revenue cap approach.

benefit consumers, the regulator, and the utility. The Department explicitly stated this goal in D.P.U. 94-158 and has since worked to advance this effort.

V. <u>The Revenue Cap Formula</u>

Q. What is the general form of a revenue cap formula?

A. A total revenue cap sets a limit on the total amount of revenue collected from all customers in aggregate. The cap is based on a measure of economic performance that is external to the regulated utility (i.e., cannot be manipulated by the utility). In general, a revenue cap formula escalates allowed revenue by $I - X + G$, where I is a measure of inflation, X is a productivity-based offset to the inflation measure, and G is a measure of the percentage change in the number of customers served. Often, a consumer dividend, or "stretch factor," is also included. However, this additional factor does not flow from the formula's derivation.

Q. What does the I factor represent?

A. The I factor is intended to be a measure of inflation that is external to the regulated firm. There are two basic approaches to its determination: industry input price inflation and economy-wide output price inflation.

Q. Please describe the approaches to determining the I factor.

A. One approach is to set the I factor equal to a measure of input price inflation. This approach was used in the U.S. railroad industry and the energy sector in Canada, but is not very common in incentive regulation plans in the United States. Another common approach is to use a measure of economy-wide output price inflation, such as the Gross Domestic Product Price Index ("GDP-PI"). This approach is the most common in U.S. incentive regulation plans, including past plans in the telecommunications industry and current utility PBR plans. This second approach has been used in previous incentive regulation plans in Massachusetts, and is the approach proposed by the Company in this proceeding.[29]

Q. How is the productivity adjustment, *X*, determined?

A. The specification of the X factor depends on the specification of the I factor.[30] When *I* is a measure of industry input price inflation, *X* is equal to the percentage change in industry TFP. When *I* is a measure of economy-wide inflation, *X* is equal to the difference between the percent change in industry TFP and the percent change in economy-wide TFP plus the difference between the percent change in economy-wide input prices and the percent change in industry input prices. However, in either case, the X factor specification will

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[29] D.P.U. 17-05 (November 30, 2017); and D.P.U. 18-150 (September 30, 2019). <u>See</u> <u>also</u> D.P.U. 96-50 (Phase I), November 29, 1996, at 273; D.T.E. 01-56, January 31, 2002, at 20; D.T.E. 03-40, October 31, 2003, at 473; and D.T.E. 05-27, November 30, 2005, at 384.

[30] As explained below, if *I* is a measure of industry input prices, *X* is determined by a measure of the expected rate of change in industry productivity. Conversely, if *I* is a measure of economy-wide output price growth (such as the GDP-PI used in previous plans in Massachusetts), then, as described below, *X* consists of a differential in a measure of the expected rate of productivity change between the industry and the overall economy, and a differential in input price growth between the overall economy and the industry. <u>See</u> Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "The Alphabet of PBR in Electric Power: Why X Does Not Tell the Whole Story," *The Electricity Journal,* 30 (2017) 30-37. Also, as explained below, *X* and the underlying measure of industry TFP growth depends on the purpose for which TFP growth is being calculated.

contain a common element; namely, a measure of the expected rate of change in industry productivity.[31]

Q. Please describe the measure of expected changes in industry productivity used in determining the X factor for an indexed cap.

A. The industry productivity concept is TFP growth, defined here as the annual percentage change in customers served across the industry minus the annual percentage change in the quantity of inputs used across the industry.

The correct specification of output for a TFP growth study depends on the purpose of the study: the output measure will differ depending on whether the purpose is to assess efficiency or to calibrate an indexed PBR cap. In general, when the purpose of measuring TFP growth is to calibrate an indexed PBR cap, the output measure will be a subset of the total outputs used in computing an efficiency measure of TFP growth.[32] In the case of a revenue cap, output growth is measured by growth in the number of customers served. The label for this specific form of productivity measure is Revenue Per Customer Cap TFP growth ("RPC TFP"), because it is specifically calibrated for use in a revenue per customer cap formula.

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31 The use of the expected rate of productivity change in setting the X factor provides incentives for productivity gains by the regulated firm. If the X factor were to be based repeatedly on actual changes in the regulated firm's productivity, price cap regulation would function in similar fashion to cost of service regulation. See Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics,* Vol. 16, 1999, at 9.

32 The reason for this has to do with what the revenue or price cap is doing: it is calibrated such that the price applied to *billable outputs* recovers the cost of inputs. If the output measure included all outputs, prices would under-recover the utility's cost to serve.

Total input includes all resources used by the unit of production in providing those services. Typically, TFP growth studies divide total input into three categories: capital, labor, and materials. TFP growth is the appropriate basis for an X factor that sets a cap on total revenue, as a comprehensive measure of productive efficiency provides a measure of the contribution of all inputs used in the production of total output. In contrast, a partial productivity measure would be more appropriate for a cap on partial revenue, like a cap on O&M related revenue.

Q. Please demonstrate that the appropriate formula for a revenue cap is *I - X + G*.

A. The $I - X + G$ formula simply represents a rearrangement of an equivalence between revenue and cost. Note that the derivation demonstrates the mathematical and economic reasoning behind including a growth factor in the revenue cap formula.

The proof begins with a widely accepted assumption in economics that, in competitive markets, revenues equal costs over the long term. Thus, under competitive conditions, the growth in the revenue of a typical company in the industry ($\%\Delta R_I$) is equal to the growth in its cost ($\%\Delta C_I$):

$$\%\Delta R_I = \%\Delta C_I \quad (1)$$

The rate of revenue change can be decomposed into the rate of change in revenue per customer ($\%\Delta RPC_I$) plus the rate of change in the number of customers served ($\%\Delta Customers_I$). Thus, total revenue is capped in the following way, where RPC abbreviates "revenue per customer":

$$\%\Delta R_I = \%\Delta RPC_I + \%\Delta Customers_I \tag{2}$$

Where the subscript *I* signifies an industry value. Rearranging:

$$\%\Delta RPC_I = \%\Delta R_I - \%\Delta Customers_I \tag{3}$$

From Equation 1, we have that, under competitive conditions, the growth in the total revenue of the typical company ($\%\Delta R_I$) is equal to the growth in its cost ($\%\Delta C_I$).

$$\%\Delta RPC_I = \%\Delta C_I - \%\Delta Customers_I \tag{4}$$

The percentage change in cost can be decomposed into the rate of input price change ($\%\Delta W_I$) plus the rate of input quantity change ($\%\Delta Q_I$).

$$\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I \tag{5}$$

Substituting $\%\Delta W_I + \%\Delta Q_I$ for $\%\Delta C_I$ yields:

$$\%\Delta RPC_I = \%\Delta W_I + \%\Delta Q_I - \%\Delta Customers_I \tag{6}$$

Rearranging:

$$\%\Delta RPC_I = \%\Delta W_I - (\%\Delta Customers_I - \%\Delta Q_I) \tag{7}$$

$$\%\Delta RPC_I = \%\Delta W_I - \%\Delta TFP_I \tag{8}$$

$$\%\Delta R - \%\Delta Customers_I = \%\Delta W_I - \%\Delta TFP_I \tag{9}$$

$$\%\Delta R_I = \%\Delta W_I - \%\Delta TFP_I + \%\Delta Customers_I \tag{10}$$

Where $\%\Delta TFP_I = \%\Delta Customers_I - \%\Delta Q_I$, which is industry TFP growth with the growth in customers as the measure of output growth. While it is assumed that the regulated company can achieve total factor productivity growth equal to the industry, it may experience different input price growth or customer growth. Equation 11 expresses the required revenue growth for a specific regulated company, *i*.

$$\%\Delta R_i = \%\Delta W_i - \%\Delta TFP_I + \%\Delta Customers_i \tag{11}$$

This revenue cap can be rewritten as $\%\Delta R_i = I - X + G$, where $I = \%\Delta W_i$, $X = \%\Delta TFP_I$, and $G = \%\Delta Customers_i$. Note that the revenue cap contains a growth factor equal to the Company's expected customer growth rate.

Because the I factor proposed by the Company is based on a measure of economy-wide output price inflation, the X factor is comprised of a combination of TFP growth and input price differentials, with the measure of the rate of change in industry RPC TFP given by $\%\Delta\ TFP_I$. That is:

$$I_E = GDPPI \tag{12}$$

and

$$X = [(\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I) \tag{13}$$

This produces the following revenue cap:[33]

$$\%\Delta R = GDPPI - [(\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I) + G \tag{14}$$

[33] Christensen, Laurits R., Philip E. Schoech, and Mark E. Meitzen, "Telecommunications Productivity." In *Traditional Telecommunications Networks,* edited by Gary Madden, 100-119. Cheltenham, United Kingdom: Edward Elgar Publishing Limited, 2003.

Q. Does the Company currently have a G factor under the revenue cap formula approved in the Company's last rate case, D.P.U. 20-120?

A. No. The revenue cap under D.P.U. 20-120 was a revenue per customer cap, given the Company's revenue per customer decoupling mechanism. Revenue per customer decoupling captured the growth rate of customers served as part of the calculation that sets annual revenues. Therefore, a G factor was not needed in the previous revenue cap formula.

Q. Is the Company proposing a G factor under its proposed revenue cap in this proceeding?

A. No. Although the Company is proposing a total revenue cap to align with the change in the Company's revenue decoupling mechanism (i.e., replacing the existing revenue per customer decoupling mechanism with a total revenue decoupling mechanism), the Company is not proposing to include a G factor in its revenue cap formula.

Q. Is there an economic justification for excluding the G factor from the Company's proposed revenue cap in this proceeding?

A. No. Under the specification derived above, the revenue cap adjusts revenues by a percentage equal to $I - X + G$. In a competitive market with an increasing number of customers, companies would eventually face bankruptcy if the percentage change in revenue each year excluded the percentage change attributable to output growth. If the revenue cap formula excludes the G factor, the annual change in revenue incorporates an implicit stretch factor equal to the annual percentage change in number of customers served. As explained previously, if customer growth continues to increase as forecasted during the PBR term, the PBR formula will not provide corresponding adjustments to total revenue, and the Company will need to identify cost efficiencies to offset any incremental cost associated with customer growth to mitigate earnings attrition.

VI. Total Factor Productivity Study and Recommended X Factor

A. Overview

Q. Please generally describe your calculation of the X factor for the Company's revenue cap.

A. Because the Company is proposing to use the GDP-PI as the I factor, the X factor consists of a TFP differential (i.e., the difference between rates of change in RPC TFP and TFP for the overall economy) and an input price differential (i.e., the difference between rates of change in input prices for the overall economy and the industry). Measures of rates of change in TFP and input prices for the overall economy are needed to compute these differentials.

Q. Is your productivity study based on a model that is the same as the model in the Company's previous base distribution rate case proceeding, D.P.U. 20-120?

A. Yes, it is. As before, we rely on a Bureau of Labor Statistics Producer Price Index ("BLS PPI") to deflate capital expenditures. In addition, S&P Global still does not collect salary information for gas distributors. Therefore, as before, we calculated the percentage of O&M expenditures attributable to labor by combining data from the most recent year of data from the American Gas Association with S&P Global data. We applied this percentage to O&M data from S&P Global to obtain a value of labor expense for each company and each year. The model is discussed in greater detail in Appendix A.

Q. Have you made updates to this model since the conclusion of D.P.U. 20-120?

A. Yes. Besides updating the data within the model, we have made small updates to refine the model itself, as follows.

First, we no longer apportion Administrative and General Expenses ("A&G") by a plant-in-service allocator. Instead, we include 100 percent of each company's A&G expenses. As explained in Appendix A, the apportionment of A&G is necessary for the calculation of electricity distribution TFP growth given the substantial production and transmission operations of integrated electric utilities, but gas distribution companies do not partake in such major non-distribution operations as to require this apportionment of A&G.

Second, we now use the average return on Moody's Baa-rated corporate bonds in the price of capital calculation (rather than Moody's Aaa bonds). This is because the Baa credit rating aligns more closely with the gas distribution sector cost of capital than Aaa bonds.[34]

Third, we have added Baltimore Gas & Electric ("BG&E") to the Northeast sample. This is because the operating conditions of BG&E are similar to those of Boston Gas.

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[34] Our calculation of the implicit rental price of capital is still quite conservative, given that the true weighted average cost of capital faced by utilities will be greater than the yield on Moody's Baa bonds.

These updates have a minor impact on the X factor calculation but improve the accuracy and reliability of the model.

Q. What is the timeframe and sample you used to determine the revenue cap TFP growth rate and input price growth for establishing the X factor?

A. The timeframe is the most recent 15 years for which data are available, 2009 to 2023. The Northeast sample consists of 31 utilities, comprising 81 percent of northeast gas utility customers.[35] As described below, the Northeast sample of utilities provides the most appropriate sample to use for the establishment of the Company's X factor.

B. Study Results

Q. How did you determine changes in gas distribution industry RPC TFP and input prices?

A. Appendix A provides the methodological details of how we determined percentage changes in RPC TFP and input prices for the gas distribution industry, including a list of firms in each sample. The comparable economy-wide sources are also provided in Appendix A.

Q. What are the results of your study of Northeast gas distribution utilities?

A. Table 2, below, provides the results for rates of change in total output, total input, RPC TFP and input prices for Northeast distribution utilities over the 2009 to 2023 period.

[35] States comprising the Northeast sample are Massachusetts, Maryland, New York, Pennsylvania, Connecticut, New Hampshire, New Jersey, and Vermont.

Table 2

**Revenue Cap TFP Growth Results for Northeast Gas Distribution Industry
2009-2023**

Period	Output	Input	RC TFP	Input Price
2009	-	-	-	-
2010	0.60%	2.20%	-1.61%	-0.39%
2011	0.41%	1.45%	-1.04%	2.46%
2012	0.69%	0.76%	-0.07%	2.60%
2013	0.57%	0.97%	-0.40%	1.94%
2014	0.65%	2.75%	-2.09%	1.73%
2015	0.69%	0.54%	0.14%	1.75%
2016	1.17%	2.88%	-1.71%	0.55%
2017	0.84%	3.56%	-2.72%	1.22%
2018	1.04%	1.52%	-0.49%	-0.17%
2019	0.75%	0.12%	0.63%	3.61%
2020	0.77%	-1.52%	2.30%	0.83%
2021	0.70%	-0.39%	1.10%	2.95%
2022	0.45%	1.68%	-1.23%	14.05%
2023	0.43%	3.83%	-3.40%	7.51%
Average	**0.70%**	**1.45%**	**-0.76%**	**2.90%**

Q. The results presented in Table 2 indicate that the average rates of change in RPC TFP for the gas distribution industry over the 2009 to 2023 period was negative for the Northeast sample. Please explain.

A. Over this period, input growth exceeded output growth for gas distributors in the Northeast sample. Table 3, below, shows that, for the Northeast sample, relatively greater capital growth (2.55 percent) contributed to total input growth being greater than output growth (0.70 percent).

Table 3

Average Output and Input Growth Northeast Gas Distribution Industries 2009-2023

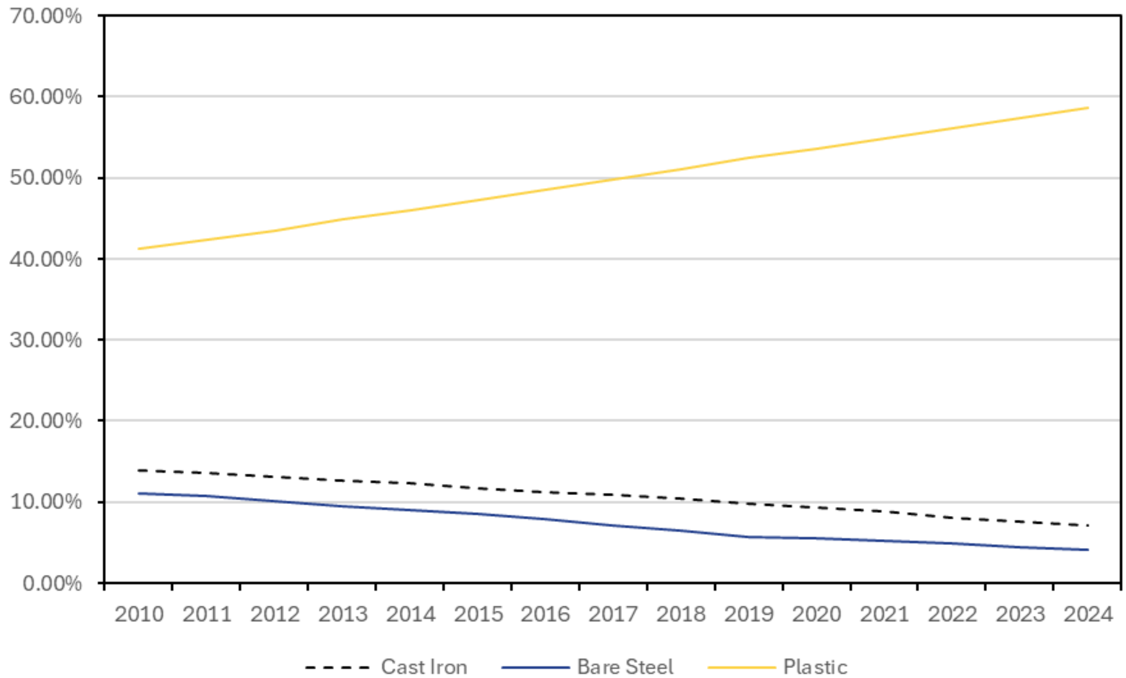
		INPUT			
Period	**Output**	**Labor**	**Materials**	**Capital**	**Total**
2009	-	-	-	-	-
2010	0.60%	-0.72%	3.36%	1.49%	2.20%
2011	0.41%	-0.06%	1.18%	1.95%	1.45%
2012	0.69%	-1.47%	-0.06%	2.43%	0.76%
2013	0.57%	1.11%	0.99%	0.65%	0.97%
2014	0.65%	2.05%	2.36%	2.02%	2.75%
2015	0.69%	-3.02%	-0.77%	2.75%	0.54%
2016	1.17%	2.42%	3.98%	1.39%	2.88%
2017	0.84%	2.73%	3.45%	3.50%	3.56%
2018	1.04%	-0.48%	0.07%	3.69%	1.52%
2019	0.75%	-5.28%	-3.38%	4.33%	0.12%
2020	0.77%	-6.67%	-5.70%	3.32%	-1.52%
2021	0.70%	-2.75%	-4.55%	2.94%	-0.39%
2022	0.45%	3.06%	-0.52%	2.52%	1.68%
2023	0.43%	4.55%	5.37%	2.76%	3.83%
Average	**0.70%**	**-0.32%**	**0.41%**	**2.55%**	**1.45%**

Q. Is there an explanation as to why inputs (i.e., capital, labor, and materials) have grown faster than output (i.e., customer growth) in the gas distribution industry over this period?

A. Yes. Over the past decade, gas distributors in the Northeastern United States have undertaken major capital investments to replace aging infrastructure and modernize gas distribution networks. This work largely consists of replacing cast iron and bare steel mains. For example, using Pipeline and Hazardous Materials Safety Administration ("PHMSA") data on miles of main pipeline, Figure 2, below, illustrates the replacement of steel and cast iron mains with plastic in the Northeast samples. Whereas in 2010, 25 percent of total distribution pipe in the Northeast was made from either cast iron or bare steel, only 11 percent of distribution pipe in 2024 was cast iron or bare steel.

Figure 2

Northeast Miles of Main by Type, as a Percentage of Total 2009-2024



In addition, several other factors have resulted in increased cost growth in recent years. For example, investments in gas safety compliance, environmental compliance, cybersecurity, and advanced metering have contributed to rising industry input growth nationwide.

The negative growth rate reflects that investment is growing faster than measured output. This does not imply declining industry efficiency. Rather, it recognizes that investment growth has risen faster than customer growth among utilities in recent years.

Q. What are the economy-wide results for changes in TFP and input prices over the 2009-2023 period?

A. Table 4, below, provides the economy-wide results over the 2009 to 2023 period. Average annual TFP growth over the 15-year study period was +0.77 percent. On average, input prices grew at a rate of 3.08 percent per year.

Table 4

Economy-Wide Results
2009-2023

Period	GDP PI	TFP	Input Price
2009	-	-	-
2010	1.19%	2.48%	3.67%
2011	2.04%	-0.41%	1.63%
2012	1.85%	0.67%	2.52%
2013	1.71%	0.58%	2.29%
2014	1.73%	0.59%	2.32%
2015	0.87%	0.90%	1.77%
2016	0.95%	0.00%	0.95%
2017	1.81%	0.64%	2.45%
2018	2.26%	0.71%	2.97%
2019	1.64%	1.19%	2.83%
2020	1.34%	-0.63%	0.71%
2021	4.45%	3.81%	8.26%
2022	6.90%	-1.12%	5.78%
2023	3.52%	1.39%	4.92%
Average	**2.30%**	**0.77%**	**3.08%**

Q. What is the X factor for the sample of Northeast gas distribution companies?

A. Table 5, below, provides the TFP growth and input price differentials and the resulting X factor using the Northeast gas distribution sample and its RPC TFP and input price growth over the 2009 to 2023 period (presented in Exhibit NG-CAEC-2 Confidential). The calculated X factor uses five more contemporary years of data since the X factor filed in D.P.U. 20-120 (years 2019 through 2023) and removes five years of older data (years 2004 through 2008). The fifteen-year average fell by six basis points, from -1.30 percent to -1.36 percent.

Table 5

***X* Factor for the Northeast Gas Distribution Sample**
2009-2023

	TFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
2009	-	-	-	-	-	-	-
2010	-1.61%	2.48%	-4.09%	3.67%	-0.39%	4.06%	-0.03%
2011	-1.04%	-0.41%	-0.63%	1.63%	2.46%	-0.83%	-1.47%
2012	-0.07%	0.67%	-0.74%	2.52%	2.60%	-0.08%	-0.82%
2013	-0.40%	0.58%	-0.98%	2.29%	1.94%	0.35%	-0.63%
2014	-2.09%	0.59%	-2.69%	2.32%	1.73%	0.59%	-2.10%
2015	0.14%	0.90%	-0.76%	1.77%	1.75%	0.02%	-0.74%
2016	-1.71%	0.00%	-1.71%	0.95%	0.55%	0.40%	-1.30%
2017	-2.72%	0.64%	-3.35%	2.45%	1.22%	1.23%	-2.12%
2018	-0.49%	0.71%	-1.20%	2.97%	-0.17%	3.14%	1.95%
2019	0.63%	1.19%	-0.56%	2.83%	3.61%	-0.78%	-1.34%
2020	2.30%	-0.63%	2.92%	0.71%	0.83%	-0.12%	2.81%
2021	1.10%	3.81%	-2.71%	8.26%	2.95%	5.31%	2.60%
2022	-1.23%	-1.12%	-0.11%	5.78%	14.05%	-8.26%	-8.38%
2023	-3.40%	1.39%	-4.79%	4.92%	7.51%	-2.60%	-7.39%
Average	**-0.76%**	**0.77%**	**-1.53%**	**3.08%**	**2.90%**	**0.17%**	**-1.36%**

Q. Table 5 indicates that the X factor for the sample of Northeast companies is negative. Is it reasonable for the X factor to be negative?

A. Yes, it is. A negative X factor largely follows from the fact that the measure of revenue cap TFP has been negative, on average, over the 2009 to 2023 period and the fact that economy-wide TFP grew faster over this period. We discussed the reasons for a negative

RPC TFP in the gas distribution industry above. Gas distribution TFP growth studies in other jurisdictions have also found negative TFP growth among gas distribution utilities.[36] The negative X factor reflects the fact that revenue requirements across the industry have grown faster than the rate of inflation in recent years.

Q. Does the fact that the X factor is negative undermine the incentives for the regulated firm to behave efficiently?

A. No. Incentive regulation provides the utility the flexibility to pursue cost-reducing initiatives and to keep the benefit of those reductions until rates are reset in the future. This is true regardless of whether the X factor is positive or negative as the efficiency incentives derive from breaking the linkage between revenues and costs. In other words, what is critical is that the X factor be invariant or external to the individual firm's actual performance. The X factor simply reflects the competitive benchmark that is expected to prevail over the term of the PBR plan. In the case of a negative X factor, the cap that the firm faces will be higher over time, all other factors held constant.

Q. In your opinion, is the TFP and Input Price growth differential based on the Northeast sample the appropriate basis of the X factor for the Company's revenue cap?

A. Yes. The calculations derived from a sample of gas distribution companies from the Northeastern U.S. provide an appropriate basis for the Company's X factor. The observations from previous proceedings still hold, that a Northeastern sample more

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[36] For example, the expert for Enbridge Gas Distribution Company in Ontario found an industry TFP growth rate of -1.35 percent. See EB-2022-0200, Exhibit 10, Tab 1, Schedule 1, filed October 31, 2022.

accurately reflects the business conditions of Boston Gas. Capital input growth has increased somewhat faster in the Northeast than Nationwide, and customer growth has been somewhat slower in the Northeast compared to the rest of the country.

Additionally, a substantial difference still exists between the National and Northeast samples with respect to the infrastructure of the utilities serving the areas. Figure 3, below, shows that although the existence of cast iron distribution pipeline as a percentage of total distribution miles is diminishing across the U.S. and the Northeast, the Northeast region and the Company's service territory still have a much larger percentage of cast iron distribution pipeline than the rest of the nation.[37] In 2024, cast iron as a percentage of total distribution miles was 13 percent for the Boston Gas service territory, seven percent for the Northeast region, and only one percent for the rest of the nation.

Distribution systems with higher proportions of cast iron and unprotected bare steel, like the Company and other companies in the Northeast, experience higher operating expenses due to gas leaks, and there is an increased emphasis on capital replacement programs in the Northeast, and Massachusetts in particular, to reduce further the number of miles of leak-prone pipe in the ground.

[37] Unprotected bare steel is also more common in the Northeast than elsewhere in the country.

Figure 3

**Cast Iron Distribution Pipeline as Percent of Total Distribution Miles
2010-2024**

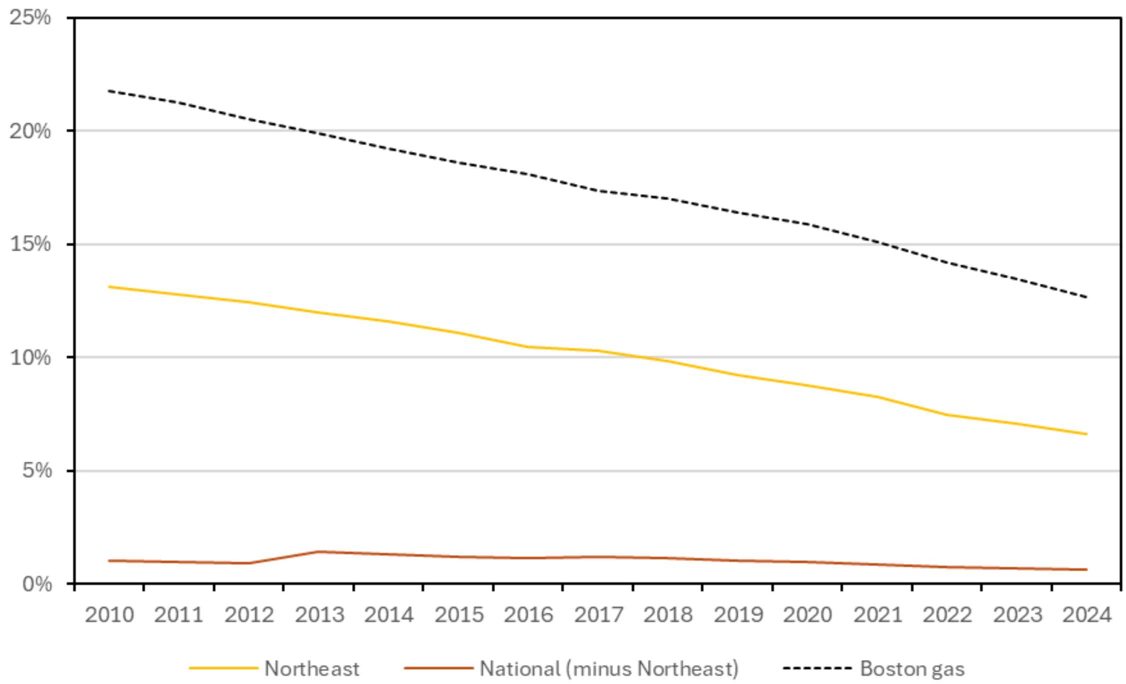
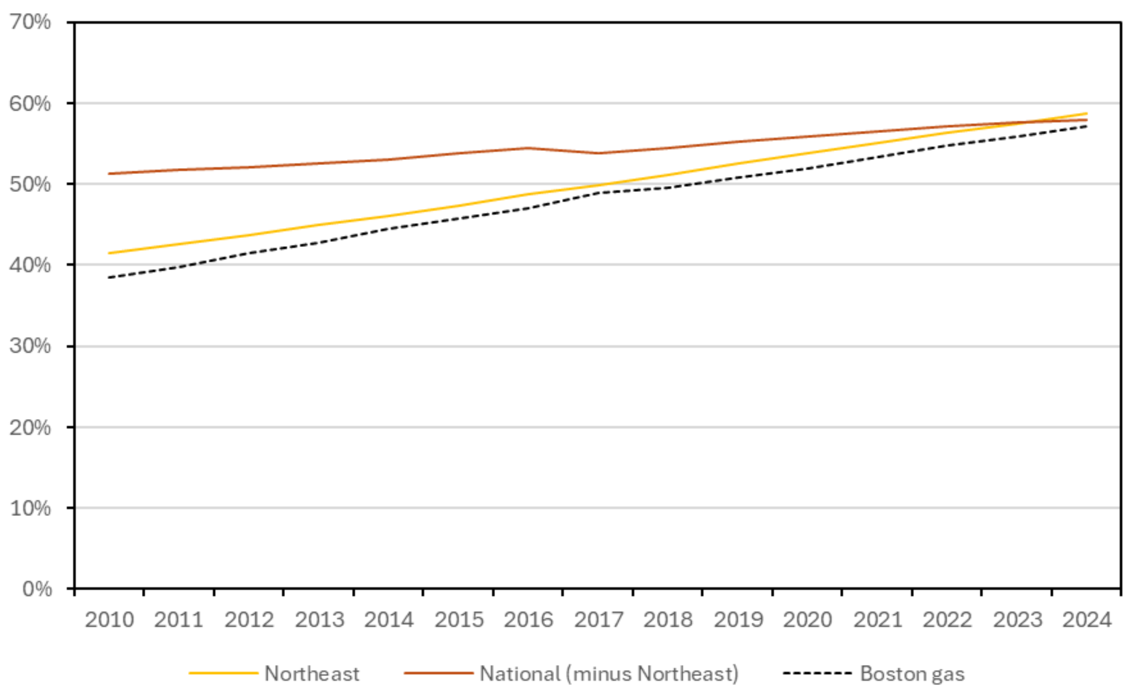


Figure 4, below, shows that the percentage of plastic pipe in the Boston Gas service territory has converged with average service territories in the Northeast and the Nation, particularly since 2020. In 2010, plastic as a percentage of total distribution miles was 28 percent for the Boston Gas service territory. Today, the percentage of plastic pipe in Boston Gas's service territory is 57 percent, compared to the national average of 58 percent.

Figure 4

**Plastic Distribution Pipeline as a Percent of Total Distribution Miles
2010-2024**



Q. **Does your X factor calculation include an adjustment for capital expenditures associated with the GSEP, proposed Gas Safety Regulation Factor ("GSRF"), or LNG capital investments?**

A. No. The X factor is calibrated to adjust an annual base revenue requirement, not for the purpose of special projects like the accelerated retirement of leak-prone pipes or the planned retirement of the Everett Marine Terminal. As discussed by the Company's PBR Panel, these investment needs are outside the scope of core business spending covered by "I-X" PBR adjustments. For this reason, cost recovery under these programs falls outside the purview of the X factor calibration. It is also worth noting that the dollar value of additional funding required to service these special projects is made more transparent by setting the X factor based on an empirical industry average TFP growth study and recovering the cost of these projects separately.

Q. Did you conduct a sensitivity analysis of changes to the model relative to the methodology used in D.P.U. 20-120 on the X factor results?

A. Yes. In Section VI (A), we describe three refinements to the model that we made since the evidence filed in D.P.U. 20-120. Table 6, below, presents the effect of each change on the results. The table also presents a sensitivity test of the X factor result using the "Kahn Methodology" used by FERC to regulate oil pipeline rates. Under the Kahn Methodology, capital inputs are obtained directly from financial accounting data (i.e., depreciation expense and allowed returns), rather than drawing on assumptions about industry capital stock and the implicit rental price of capital, as in TFP growth studies. The result (-2.18 percent) indicates that our approach to measuring capital is conservative.[38]

Table 6: X Factor Sensitivity Tests

TFP Study Versions	X Factor
2025 Recommendation	-1.36%
A&G Allocated by Plant	-1.46%
Moody's AAA Used	-1.20%
Baltimore Gas excluded from Northeast sample	-1.27%
Kahn Methodology X Factor	-2.18%

[38] We considered this sensitivity test following recent work on evidence filed regarding the Kahn Methodology in FERC's Five-Year Oil Price Index proceeding. See the CA Energy Consulting evidence filed on behalf of the Canadian Association of Petroleum Producers under FERC Docket RM25-2-000, December 24, 2025.

VII. Cost Benchmarking and Consumer Dividend

Q. What is a consumer dividend in the context of a revenue cap in a PBR plan?

A. The consumer dividend reflects a portion of the regulated company's expected gains in productivity during the PBR term relative to the industry average. It effectively increases the X factor in the company's PBR formula, thereby reducing the company's annual allowed revenue growth and providing customers with immediate benefits over the PBR term. The consumer dividend is also sometimes referred to as a "stretch factor" and builds an assumption into the PBR formula that the company will immediately experience expected gains in productivity.

Q. How should the consumer dividend be set?

A. Ideally, one could accurately predict a company's cost efficiency trajectory over the PBR term and share a predetermined fraction of these efficiency gains with customers during the plan.[39] However, while economic theory predicts that a company will reduce costs to maximize profit under PBR, it is not possible to know with certainty what its efficiency gains will be during the term.

Q. How is the consumer dividend set in practice?

A. In practice, a cost benchmarking study and the regulator's judgement largely determine the consumer dividend. A cost benchmarking study provides an estimate of the company's

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[39] For example, suppose a company is moving from cost of service to PBR and is expected to reduce its costs by 0.5 percent per year from efficiency gains. If 50 percent of this is shared with customers, a consumer dividend of 0.25 percent would be imposed.

cost efficiency level by comparing the costs of its operations to the costs experienced by other utilities in the same industry, controlling for relevant exogenous factors. If the study determines that the company is less cost efficient than peer companies with comparable operating conditions, it receives a higher consumer dividend, on the basis that a less efficient company is expected to achieve higher efficiency growth as it pursues greater profit under PBR.

This approach is imperfect for two reasons. First, all benchmarking studies are confounded at least to some degree by unobservable variables. If the study does not control for every aspect of a company's exogenous operating conditions, then its estimate of cost efficiency will be biased. Second, even if the study provided an accurate picture of a company's relative efficiency level, it is not clear how long it will take the company to arrive at the frontier, or the least-cost choice of inputs given its operating conditions. In other words, there is no clear mapping between the company's performance in even an ideal cost benchmarking study and the consumer dividend, which should be based on what cost efficiencies the company can achieve during the PBR term. Regulators understand these imperfections; they combine the information that can be inferred from cost benchmarking analysis with other available information to arrive at a projection of the company's expected efficiency gains relative to the industry and the resulting consumer dividend.

Q. What is your proposed consumer dividend for Boston Gas?

A. We recommend a consumer dividend of 0.20 percent.

Q. What is the basis for this recommendation?

A. This recommendation is based on three factors: (1) Department precedent; (2) economic theory; and (3) the results of the cost benchmarking study discussed below. Although the precise value of any consumer dividend inevitably relies on judgment.

Q. Please explain why the Company is proposing a consumer dividend that is lower than the consumer dividend established in D.P.U. 20-120.

A. Consumer dividends should reflect the anticipated cost efficiencies the company will achieve during the PBR term. The Company's current consumer dividend is 0.30 percent. Following the first PBR term, economic theory suggests that although a company will continue to make efficiency improvements, efficiency *growth* is unlikely to increase in subsequent PBR terms. The reason is that the company will adopt the least-costly means of increasing efficiency in the first term to maximize profit. This theory is supported by the cost benchmarking study, which shows a significant improvement in cost performance by Boston Gas during the first years of its plan. In subsequent terms, efficiency gains become harder to achieve or are exhausted altogether. Because the consumer dividend is proportional to expected efficiency gains, it should fall with the expected reduction in efficiency growth.

Beyond supporting a reduction in the consumer dividend, however, the evidence and existing theory do not imply a particular value of the consumer dividend. Therefore, we examine recent consumer dividends approved by the Department for peer companies in order to offer a more precise recommendation. Our findings suggest that while the Company's unit cost performance has not been as strong as that of NSTAR Gas Company d/b/a Eversource Energy, which received a consumer dividend of 0.15 percent in D.P.U. 19-120, the Company's performance has been superior to that of Fitchburg Gas and Electric d/b/a Unitil Corporation, which received a consumer dividend of 0.25 percent in D.P.U. 23-81. Thus, while the theory and empirical findings are consistent with a reduction in the consumer dividend from 0.30 percent, a specific reduction to 0.20 percent is consistent with Department precedent.

Q. What information does a benchmarking study provide that is relevant to setting the consumer dividend in a second PBR term?

A. A cost benchmarking study that combines data before and after a transition to PBR provides an estimate of how a company's costs compare to its peers near the end of its PBR term and how they have changed after transitioning from cost-of-service regulation. An estimate of a company's cost performance can be used together with economic theory to inform the consumer dividend. For instance, if the benchmarking study estimates that the company made considerable efficiency gains and its costs are similar to those of companies with similar operating conditions, the regulator may expect that the company cannot continue to reduce its costs at the same rate while meeting its obligations, and will thus set a lower consumer dividend.

Q. What methods did you use to measure Boston Gas's efficiency level relative to peer companies?

A. We have performed a unit cost benchmarking study similar to those filed in prior PBR proceedings using three peer groups. The first set of analyses involves an annual comparison of Boston Gas's unit costs to the average unit costs for both a National sample and a regional Northeast sample. In the benchmarking study filed in D.P.U. 20-120, a manually selected sample of peer companies was also used as a more targeted comparison group based on aging assets and population density. In this proceeding, instead of manually selecting a targeted sample, we have performed an econometric benchmarking analysis that compares Boston Gas's costs to its predicted costs based on its operating conditions.

Q. Why did you perform an econometric benchmarking study in addition to a unit cost study?

A. A company with high unit costs may be inefficient, but these costs may also be explained by conditions outside of the company's control like state regulatory objectives or higher input prices. An econometric benchmarking study has the advantage of controlling for more features of the Company's operating environment. This analysis aligns with the Department's finding in D.P.U. 20-120, which stated, "[t]he Department has noted that econometric benchmarking is a preferred method for controlling for differing circumstances between companies in a sample."[40]

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[40] D.P.U. 20-120, at 86.

Q. Please describe the econometric cost benchmarking analysis.

A. An econometric benchmarking study involves estimating a regression model, which is a statistical tool that predicts the cost for a company based on its operating conditions. The model produces a benchmark estimate of cost that is analogous to the National and Northeast sample averages, but is adjusted to account for differences in operating conditions between the Company and its peers. The variables controlled for in the econometric benchmarking study include input prices, total customers, population density, the share of mains miles comprised of leak-prone pipe,[41] the cumulative change in the share of leak-prone pipe miles to control for capital replacement projects, and year fixed effects that control for industry shocks common to all companies. While this is an improvement over the unit cost approach for the purpose of uncovering company efficiency, it is important to note that the model will inevitably fail to capture all relevant variables. For instance, lumpy investment will cause spending cycles that are not controlled for in the model; a company may undertake necessary capital investment projects during the PBR term and the sudden rise in spending may make a company look less efficient than it is. Nevertheless, the result of this study can serve as a useful additional point of comparison as it controls for variables that are not controlled for in a unit cost comparison. Details on the econometric benchmarking methodology and results are provided in Appendix C.

[41] Leak-prone pipe is defined as mains pipe comprised of either cast iron or unprotected bare steel.

Q. Please provide a summary of your findings from the cost benchmarking study.

A. Table 6, below, summarizes the results of the unit cost and econometric benchmarking results for Boston Gas. In the unit cost study, the Company's costs per customer are compared to two benchmarks: (1) a National sample average; and (2) a Northeast sample average. In the econometric benchmarking study, the Company's costs are compared to the prediction from the econometric model; this prediction can be interpreted as the average cost of companies in the National sample that have observable operating conditions similar to those of Boston Gas. The "score" shows the percentage by which actual costs are above predicted cost – positive values mean costs were higher than the benchmark and negative values mean costs were below the benchmark. Therefore, a reduction in the score indicates that the Company improved its cost performance. Similarly, a lower rank indicates superior cost performance, so that reductions in the Company's rank imply an improvement in performance.

Three measures of cost are considered: (1) O&M cost, which refers to distribution operation and maintenance expense; (2) OM&A cost, which combines O&M cost and A&G expense; and (3) total cost, which combines OM&A cost and capital costs. A detailed description of what is included in each of these cost categories can be found in Appendix A.

Overall, the Company's cost performance improved. Significant improvements in operational cost performance were measured across studies and total cost performance improved in the econometric study, which controls for important cost-driving factors like leak-prone pipe replacement projects.

Table 6: Summary of Boston Gas's Cost Benchmarking Results

Method	Cost Measure	Score 2017-2019	Score 2021-2023	Rank 2017-2019	Rank 2021-2023	Score Change	Rank Change
Unit Cost (National)	O&M	57.0%	17.1%	77	63	-40.0%	-14
	OM&A	37.6%	26.8%	73	69	-10.8%	-4
	Total Cost	35.3%	33.7%	73	74	-1.6%	1
Unit Cost (Northeast)	O&M	25.5%	-7.4%	26	15	-32.9%	-11
	OM&A	7.6%	3.2%	21	19	-4.4%	-2
	Total Cost	6.0%	6.7%	19	20	0.7%	1
Econometric	O&M	53.2%	16.9%	42	33	-36.3%	-9
	OM&A	32.3%	22.5%	39	34	-9.8%	-5
	Total Cost	20.4%	14.7%	36	33	-5.6%	-3

Note: Blue cells indicate an improvement in performance and red cells indicate a decline. There are 86 companies in the National sample, 31 in the Northeast sample, and 48 in the econometric sample.

Q. What are the findings of the unit cost benchmarking analysis?

A. The results of the unit cost analysis are summarized in Table 6, which shows how the Company's cost performance changed after transitioning to PBR in 2021 using three-year averages before and after the regime change. In order to mitigate the impacts of the COVID-19 pandemic and the merger between Boston Gas and the former Colonial Gas in 2020, the Company's cost performance between 2017 and 2019 is used to summarize cost performance under cost of service. Because of infrastructure characteristics driving lifecycle maintenance and replacement work on the Company's gas distribution systems discussed in the pre-filed testimony of the Company's Capital Expenditures Panel, Exhibit

NG-CAPEX-1, total cost performance is the less relevant measure of efficiency for purposes of benchmarking controllable unit costs against national and regional peers. OM&A[42] cost is more controllable, but contains A&G expenses like pension costs, property insurance, and Information Technology capital investments that are largely exogenous. The Company has the most control over O&M costs. Relative to the national average, Boston Gas's unit O&M cost fell from 57 percent to 17.1 percent above the national average, with a corresponding improvement in its national rank from 77th to 63rd out of 86 companies. Relative to the Northeast sample, its unit O&M cost fell from 25.5 percent above average to 7.4 percent *below* average, leading to a rank improvement from 26th to 15th out of 31 companies. Incorporating A&G expense, unit OM&A cost fell from 37.6 percent above the national average between 2017 and 2019, to 26.8 percent above the national average between 2021 and 2023, leading to an improvement in its rank from 73rd to 69th out of 86 companies. Relative to the more pertinent Northeast sample, which will better account for Boston Gas's operating conditions, the Company's unit OM&A cost fell from 7.6 percent to 3.2 percent above the Northeast average, leading to an improvement in its rank. Overall, this indicates a strong improvement in operational cost performance.

The Company's unit total cost fell from 35.3 percent to 33.7 percent above the national average. Relative to the regional sample, unit total cost rose slightly from 6 percent above

[42] OM&A refers to O&M and administrative and general expense jointly.

average to 6.7 percent above average. Overall, the Company's unit total cost rank was essentially unchanged, falling (worsening) one slot.

In summary, the unit cost study suggests that the Company's operational cost performance improved after transitioning to PBR. The change in total cost performance appears to be more ambiguous. However, it is difficult to assess total cost performance from the unit cost study alone due to the increased capital expenditures for required infrastructure maintenance and replacement projects.

Q. What are the findings of the econometric cost benchmarking analysis for Boston Gas?

A. Relative cost efficiency estimates from the operational and total cost models for Boston Gas are also summarized in Table 6, above. Boston Gas's O&M cost score improved from 53.2 percent to 16.9 percent and its corresponding rank in the econometric sample improved from 42nd to 33rd out of 48 companies.[43] The Company's OM&A cost score improved from 32.3 percent to 22.5 percent, with a rank improvement from 39th to 34th. The Company's total cost score improved from 20.4 percent to 14.7 percent, corresponding to an improvement in its rank from 36th to 33rd. Thus, in the econometric study, the Company's total cost and operational cost performance improved as measured by both its score (its cost relative to the model's prediction) and its score ranking.

[43] The econometric sample is smaller than the National sample because a company must have non-missing and non-zero values for the variables in the model to be included. Furthermore, companies with very small numbers of customers or leak-prone pipe miles are removed so that the results are not impacted by companies that bear little resemblance to Boston Gas, which is in the 77th and 98th percentile in these variables, respectively.

Q. What aspects of the cost benchmarking findings influence your recommended consumer dividend?

A. Across all benchmarking approaches, the Company's operational cost performance improved substantially. As mentioned above, operational cost performance may be the more relevant measure of efficiency given the lifecycle maintenance and replacement work on the Company's gas distribution systems, which are less controllable by the Company. While the unit cost analyses provide less clarity on the Company's total cost performance improvement, the econometric analysis suggests a clearer improvement in total cost performance. These findings support a reduction in the consumer dividend.

Q. What other aspects of Boston Gas's PBR proposal are relevant when evaluating the consumer dividend?

A. The Company has proposed a revenue cap without a growth factor. This implies that revenues collected through the index formula will not rise over the PBR term in response to customer growth. Because total costs rise with customer growth, as shown in Appendix C, returns may decrease as total customers increase if sufficient revenue is not collected elsewhere in the plan. Consequently, the absence of a growth factor in the revenue cap can be interpreted as an implicit consumer dividend. The Company's historical customer growth rate from 2010 to 2023 is 1.4 percent. Thus, all else equal, the Company is effectively proposing a stretch factor of 1.6 percent (1.4 percent + 0.2 percent) unless customer growth attenuates due to changes in policy and regulation (e.g., successful electrification programs or modifications to the contributions in aid of construction ("CIAC") policy under consideration in D.P.U. 25-41), or other factors.

Q. Please summarize your testimony as it relates to your recommended consumer dividend.

A. If the Department approves a PBR plan in this proceeding, the size of the consumer dividend should be proportional to the Company's expected efficiency gains relative to the industry. Economic theory suggests that the most significant efficiency gains will occur in the first PBR term. The Company's strong improvement in operational cost performance – the area in which it can exert the most control over its costs – supports this. As additional efficiencies become progressively costlier to find and implement, one should expect less efficiency growth in the next PBR term. This supports a reduction to 0.25 percent or lower from the Company's current consumer dividend of 0.30 percent. The cost benchmarking study combined with Department precedent can be used to refine the recommendation further. The Company's unit cost performance as shown in Appendix B is estimated to fall between that of NSTAR Gas Company and Fitchburg Gas and Electric, which currently operate with consumer dividends of 0.15 percent and 0.25 percent, respectively. Therefore, a consumer dividend of 0.20 percent is consistent with Department precedent, as well as economic theory and the cost benchmarking analysis.

VIII. <u>Evaluation of Company's PBR Proposal</u>

A. PBR Term

Q. What is the number of years of the Company's proposed PBR plan, and how does this align with precedent?

A. Boston Gas has proposed a revenue cap term of five years.[44] In prior proceedings, the Department has found that a well-designed PBR framework should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions.[45] In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs.[46] A five year term provides an opportunity to realize these benefits while balancing risks associated with rate stay-out periods. Indexed cap plans in British Columbia, Alberta, and Ontario, and Hawaii are five years in duration, as are incentive regulation plans in Australia, New Zealand, and Great Britain. While there is no concrete rule that requires a plan to be this number of years, it is a reasonable proposal in line with precedent and practice both in Massachusetts and elsewhere.

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44 Based on the timing of the filing, the proposed term of the PBR Plan would technically run from December 1, 2026 to September 30, 2031, which is 58 months, and not 60 months. Conversely, the timing of the filing allowed customers to avoid a change in base rates for two additional months, moving the rate change from October 1, 2026 (one year from the Company's most recent PBR adjustment on October 1, 2025) to December 1, 2026. Therefore, for ease of reference, the Company refers to the proposed PBR Plan term and stay-out commitment as a five-year term.

45 D.P.U. 96-50 (Phase I), at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272; D.P.U. 18-150, at 53; D.P.U. 17-05, at 402; D.P.U. 19-120, at 63; D.P.U. 20-120, at 70.

46 D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

B. PBR Formula

Q. What is the specification of the PBR formula proposed by Boston Gas?

A. Boston Gas has proposed to operate under a revenue cap formula specified as follows:

$$\%\Delta R_{base} = \%\Delta GDPPI - (-1.36\%) - 0.20\% \tag{15}$$

Where $\%\Delta R_{base}$ represents the annual percentage change in the Company's base revenue requirement, which excludes revenues associated with cost recovery for GSEP and certain LNG expenditures. This formula reflects an X factor of -1.36 percent and a consumer dividend of +0.20 percent. Both the X factor and the consumer dividend will remain the same throughout the PBR Plan term. The inflation factor, GDP-PI, will be updated with the most recent available data as reported by the Bureau of Economic Analysis.

Q. What is your assessment of this proposed PBR formula?

A. The proposed formula adjusts base revenues using a reasonable measure of inflation and an empirically calibrated X factor. These elements of the formula are firmly aligned with the economic principles supporting revenue caps.

Economic literature has not established a firm basis for including or calibrating a consumer dividend in indexed cap frameworks (note that a stretch factor is not an element of the PBR formula as derived in Equations 1 through 14, above). However, most PBR frameworks in North America include some form of consumer dividend or "stretch factor," usually set based on a combination of cost benchmarking and expert judgement. Drawing from the results of a cost benchmarking analysis, we provide a recommendation of 0.20 percent.

The Company has proposed a consumer dividend of 0.20 percent, in line with this recommendation. This consumer dividend value should be considered in context; the Company is now on its second generation PBR framework, operates in a more expensive state relative to its peers in the TFP growth analysis,[47] and does not propose to operate with a growth factor. All else equal, the proposed consumer dividend of 0.20 percent means that the Company must operate more efficiently than its comparators in order to achieve its allowed rate of return.

The exclusion of the growth factor amounts to an additional implicit consumer dividend since the Company no longer operates under revenue-per-customer decoupling. However, our understanding is that the Company will be able to recover a portion of the cost of adding new customers through its CIAC under the existing CIAC policy.[48] This means that although the Company has an implicit consumer dividend built into its PBR formula as described in Section VII, the value of the implicit consumer dividend is reduced somewhat.

[47] For example, research from the Missouri Economic Research and Information Center indicates that Massachusetts is the second most expensive state in the country, behind Hawaii and above all other states in the Northeast sample. (See here: https://meric.mo.gov/data/cost-living-data-series). The Bureau of Economic Analysis publishes a regional Personal Consumption Expenditures report that ranks Massachusetts above all other states in the Northeast sample except for New Jersey. (See here: https://www.bea.gov/news/2024/real-personal-consumption-expenditures-state-and-real-personal-income-state-and).

[48] The Department is considering changes to the CIAC policy under D.P.U. 20-80-E; however, currently, the Company's CIAC recovery is approximately 10 percent of total connection costs, on average.

C. Earnings Sharing Mechanism

Q. Please describe the Company's proposed Earnings Sharing Mechanism ("ESM").

A. Boston Gas has proposed an ESM with the following parameters. The Company would be permitted to retain earnings up to 100 basis points of its allowed ROE. Above a 100-basis point threshold above the authorized ROE, the Company would share with customers 50 percent of earnings and retain 50 percent of those earnings. For all earnings above a 200-basis point threshold above the authorized ROE, the Company would share with customers 75 percent of earnings and retain 25 percent of those earnings. The proposed ESM does not incorporate earnings deficits, which means Boston Gas's customers do not face any price risk if the Company falls below its target return.

Q. Does the Company's ESM align with the Department's regulatory objectives and regulatory precedent?

A. The proposed ESM is consistent with Department precedent.[49] ESMs reduce the cost efficiency incentives of PBR by removing a portion of the profit gained from cost-cutting efforts. For this reason, we generally do not support ESMs unless the deadband is larger or particular circumstances suggest the need for such a mechanism. However, they are a common guardrail for PBR plans, and the proposed ESM aligns with similar frameworks in other jurisdictions.

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[49] The proposed ESM is similar to Boston Gas's existing mechanism, which shares earnings 75/25 above 200 basis points from the authorized ROE.

D. Exogenous Factor

Q. What is a Z factor?

A. A Z factor is ordinarily included in a PBR plan to provide revenue support above a certain threshold for costs incurred related to exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

Q. What is the Department precedent for including exogenous factors in a utility's PBR framework?

A. The Department has recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, they may be appropriate to recover (or return) through the PBR mechanism.[50] The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the inflation factor, GDP-PI.[51] The Department has listed examples of Z factors, including incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.[52] Z factors often include a materiality threshold, under which a company must absorb the costs with no recourse. In

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[50] D.P.U. 94-158, at 62.

[51] D.P.U. 94-50, at 172-173.

[52] D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173.

Massachusetts, this value equals the product of 0.001253 and the Company's total operating revenues in the test year.

Q. Is the Z factor proposed by Boston Gas reasonable?

A. Yes. The Company has proposed a Z factor similar to Z factors approved by the Department in prior PBR framework decisions,[53] with a modification to include capital-related exogenous costs. Boston Gas proposes to recover exogenous costs that exceed a threshold value in line with Department precedent, as discussed in the testimony of the Company's PBR panel. After 2025, the materiality threshold will be updated by the change in the inflation factor.

The inclusion of capital-related costs aligns with Z factors in other jurisdictions, including Alberta,[54] Ontario,[55] and British Columbia.[56] There is no economic reason to disallow capital-related revenue recovery due to events beyond the Company's control.

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[53] See, e.g., Boston Gas Company d/b/a National Grid, D.P.U. 20-120, at 96, fn.60 13 (2021). However, in D.P.U. 20-120, the Department allowed the Company only to file for exogenous costs on O&M cost changes and not for adjustments to the annual revenue requirement of cumulative capital investment.

[54] "2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities," Alberta Utilities Commission, October 4, 2023.

[55] "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," Ontario Energy Board, July 14, 2008.

[56] "Order Number G-69-25, In the Matter of the Utilities Commission Act, RSBC 1996, Chapter 473 and FortisBC Energy Inc. and FortisBC Inc. 2025 to 2027 Rate Setting Framework," British Columbia Utilities Commission, March 18, 2025.

E. Scorecard Metrics

Q. Please summarize the Company's current performance metrics filings before the Department.

A. Our understanding is that Boston Gas currently files metrics in two locations: (i) an annual service quality report that contains some metrics tied to predetermined financial penalties; and (ii) PBR scorecard metrics, as part of the annual PBR filing.

Q. What set of metrics has Boston Gas proposed to report as PBR scorecard metrics over the PBR term?

A. The Company has proposed seven metrics across four categories: (1) Affordability, (2) Safety and Reliability, (3) Customer Satisfaction and Engagement, and (4) Emissions Reductions. The proposed metrics incorporate modifications from the existing PBR scorecard metrics. These modifications aim to improve the quality and value of the metrics. The details of these metrics are outlined in Table 1 of the Company's PBR panel testimony, Exhibit NG-PBRP-1.

Q. Do these metrics align with scorecard metrics reported in other jurisdictions?

A. Generally, yes. Regulatory authorities in jurisdictions that we are familiar with where gas distributors operate under PBR (British Columbia, Alberta, and Ontario) require gas distribution companies to file performance metrics on an annual basis. These reported metrics vary by jurisdiction, but the categories are similar. The proposed metrics are also similar to those reported by Eversource and Unitil. If accepted, the Affordability metric would be unique relative to other gas distributors operating under PBR. We note that Boston Gas has not included in its scorecard some metrics that are common in other jurisdictions (e.g., worker accidents); however, the Company's annual Service Quality Report already covers these metrics. These other jurisdictions generally do not have two separate reporting channels for communicating performance.

Q. Are the proposed scorecard metrics reasonable?

A. Yes. Scorecard metrics should balance the goal of providing information to customers, the regulator, and utility staff with the cost of measuring and maintaining the systems required to administer them. The Company has proposed a set of metrics that measure outcomes related to the Department's key regulatory objectives under PBR, provide information that pertain to outcomes largely controllable by the company, and do not impose an undue burden on Company staff to administer.

F. Evaluation of the Proposed Framework

Q. Taken together, do the elements of the Company's proposed plan align with the Department's regulatory objectives?

A. Yes. Boston Gas has proposed to continue operating under a reasonably conventional revenue cap framework in which base revenues are annually adjusted by inflation, an adjustment factor, and a consumer dividend. Revenue cap frameworks are known to promote X efficiency, allocative efficiency, and dynamic efficiency, as well as reduced administrative burden. These four outcomes meet the Department's corresponding objectives outlined in Section IV. The framework allows Boston Gas to deliver benefits to consumers in the form of contained rate growth and safe, reliable service. Through these mechanisms, the Company's proposed plan meets the Department's other objective, "the facilitation of new services." [57]

Q. Does the Company's proposal align with economic theory and PBR practice in other jurisdictions?

A. Generally, yes. As stated above, we are skeptical of the exclusion of a growth factor. However, the Company's proposed framework would provide cost efficiency incentives regardless of the allowed annual percentage change in revenue. The risk with such an approach is a revenue shortfall that results in earnings below the Company's cost of capital. Such a risk is not mitigated by the asymmetric ESM, because the ESM does not allow for the recovery of revenue deficiencies.

The Company has also proposed to recover certain capital-related revenues using mechanisms external to the PBR formula. These mechanisms can be included in the plan provided they recover only targeted costs arising from activity other than standard gas distribution operations. We are not aware of any indexed cap framework in North America that regulates gas or electric utilities without some additional support for the recovery of certain capital investments.

[57] D.P.U. 94-158, at 53.

IX. Summary and Conclusions

Q. Please list the elements of the Company's proposed PBR Mechanism.

A. Boston Gas has proposed to operate under a revenue cap plan similar to its current framework. Under the proposed framework, the Company's allowed base revenue will adjust each year according to a percentage equal to $I - X - CD$, where CD is the consumer dividend. Specifically, revenue will adjust according to GDP-PI growth minus -1.36 percent and minus +0.20 percent. This plan deviates slightly from the recommendations of CA Energy Consulting's experts given the additional risk assumed by the Company associated with the following. First, the revenue cap formula does not contain a growth factor, which may lead to under-recovery of the Company's base revenue requirement. Second, it proposes an asymmetric ESM that shares with customers between 50 percent and 75 percent of earnings above a two-step deadband, which may weaken cost efficiency incentives. We understand that the Company must balance these risks with Massachusetts precedent, which informs the Department's decisions. In general, however, we believe the Company has proposed a reasonable and conventional revenue cap plan that is consistent with the Department's regulatory objectives.

Table 7, below, provides a summary of the elements of the Company's proposed PBR Plan.

Table 7: Summary of National Grid's PBR Proposal

PBR Component	CA Energy Consulting Recommendation	Company Proposal
Indexed Cap	Revenue Cap	Revenue Cap
Inflation Measure	GDP-PI	GDP-PI
X Factor	-1.36%	-1.36%
Growth Factor	%ΔCustomers	None
Capital Supplement	To address unique capital recovery needs	GSEP, GSRF, LNG
Z factor	Capital and O&M	Capital and O&M
Earnings-Sharing Mechanism	As needed to address perceived risk.	>100 bps: 50% sharing >200 bps: 75% sharing
Consumer Dividend	0.20%	0.20%
PBR Term	5 years	5 years

Q. Please summarize your recommendations regarding this proposal.

A. In reviewing the PBR framework proposed by Boston Gas, we have found that the Company has developed a plan that adheres to the Department's precedent and meets the regulatory objectives of PBR. The proposed plan will provide benefits to customers in both the short term and the long term through efficiency gains by the Company, given that it operates under a revenue cap with a consumer dividend and an ESM. For this reason, the Company's proposed PBR framework is in the public interest and should be approved by the Department.

Q. Does this conclude your joint testimony?

A. Yes.

INDEX OF EXHIBITS AND WORKPAPERS

APPENDIX A. STUDY METHODS

This study of Total Factor Productivity ("TFP") growth is specifically designed to be used in developing the X factor for a revenue per customer cap. *Revenue per customer cap TFP growth* ("RPC TFP") is specified as:

$$\text{RPC TFP} = \%\Delta TFP_I = \%\Delta Customers_I - \%\Delta Total\ Input_I$$

Where $\%\Delta Customers_I$ represents the measure of industry output for RPC TFP and $\%\Delta Total\ Input_I$ is an index of industry total input. This study is performed using the methodology and approach accepted by the Massachusetts Department of Public Utilities in numerous proceedings over the past decade. However, a key difference between other recent gas distribution company revenue cap proceedings and the present case is that Boston Gas Company d/b/a National Grid ("Boston Gas" or the "Company") will not operate under revenue per customer decoupling under its proposed plan. Thus, the X factor is calibrated for a Performance-Based Ratemaking ("PBR") framework that assumes a separate provision for revenue associated with customer growth which no longer exists. This means that, all else equal, the revenue cap formula will under-recover revenue relative to the derived revenue cap formula presented in Section V of this testimony.

As in past TFP growth studies filed in Massachusetts, the model incorporates Customer Service and Information ("CS&I") expenses and customer accounts and sales expenses, subtracting Demand Side Management ("DSM") expenses. Administrative and general ("A&G") expenses were also included in the computation of Total Input.

As accepted in D.P.U. 20-120, this study uses the Producer Price Index for Construction, published by the Bureau of Labor Statistics.

Output

Because the results of the study are designed to be applied to a revenue per customer cap, it is appropriate to base the output measure on the number of customers served. In a revenue per customer cap, the number of customers is the "dual" output measure to the revenue per customer cap (that is revenue per customer times the number of customers equals total revenue).

The data source for the output measure is "Sales to Ultimate Customers" found in the U.S. Energy Information Administration ("EIA") 176 reports, though for companies and years for which EIA did not have this data, customer counts were supplemented using S&P Global data.

Distribution Labor

Because S&P Global does not maintain records of wages and salaries by company, we calculated labor input as a percentage of operations and maintenance ("O&M") costs across the gas distribution industry. The percentage of O&M expenses attributable to labor was calculated by multiplying the average industry compensation[58] by the average number of employees at each company in the sample for which data was available,[59] to obtain a total compensation value for each company. For each company, this total compensation value was then divided by total O&M expenses to obtain an estimated labor percentage of O&M. The company-level labor percentage

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[58] Total Compensation was obtained from the American Gas Association Table 13.2A, "Gas Utility Industry Employees and Payroll by Type of Payroll and Type of Company."

[59] Average number of employees by company was obtained from SNL Financial.

of O&M was averaged across all companies. This calculation estimated that 19.0 percent of O&M expenses were attributable to labor.[60] This value was corroborated using Input/Output data published by the Bureau of Economic Analysis ("BEA").[61] The price of labor is based on the Bureau of Labor Statistics Employment Cost Index for utility industry total compensation,[62] with the quantity index of labor derived by dividing the cost of labor by its price.

Distribution Materials

To measure distribution materials input, we base materials cost on operating and maintenance expense for distribution from S&P Global, less labor compensation described above. The price of materials is based on the BEA Gross Domestic Product Price Index, while the quantity of materials is derived by dividing the cost of materials by its price.

Components of O&M Expenses

Labor and materials inputs were derived from annual O&M expenses for each company in the sample. The O&M expenses in this model were calculated by summing the following accounts:

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60 This methodology expanded upon the work by London Economics, Inc. in Docket D.P.U. 19-120.

61 The BEA publication can be found here: https://apps.bea.gov/iTable/?reqid=1602&step=2&Categories=Core&isURI=1&_gl=1*18wesx6*_ga*NjE2MTc2NzQ2LjE3NTU1MzYzMzQ.*_ga_J4698JNNFT*czE3NTU1MzYzMzQkbzEkZzEkdDE3NTU1MzcwMDQkajU3JGwwJGgw. This data suggests between 42 percent and 47 percent of O&M expenses are attributable to labor, using the following calculation:

$$\text{Labor, as a Percentage of O\&M} = \frac{\text{Compensation of Employees}}{(\textit{Total Intermediate Inputs} - \textit{Gas Extraction}) + \textit{Compensation of Employees}}$$

62 Bureau of Labor Statistics, Total Compensation for Private industry workers in Utilities, 12-month percent change, Series ID CIU2014400000000I (http://www.bls.gov/ncs/ect/).

Name of Account
Total Distribution O&M Expenses
Total Underground Storage Expenses
Total Other Storage Expenses
Customer Service & Information Expenses
Customer Accounts Expenses
Sales Expenses

From this summation, the value from Account 905 was subtracted for Massachusetts companies and Account 908 for non-Massachusetts companies, as this account contains DSM costs.

Administrative and General Labor and Materials

In the past, CA Energy Consulting has apportioned A&G expenses for gas and electricity distribution TFP growth studies, because A&G expenses are comprised of joint and common costs that pertain to activities that span a utility's functional components—distribution, transmission and production—and are not dedicated to the distribution function. The previously accepted methodology was to multiply a firm's total A&G expenses, less franchise requirements, for each year in the sample by the annual average across all firms in the sample of the percentage of distribution plant relative to total plant.

However, given that gas distribution utilities, unlike electric utilities, generally operate as distribution-only utilities—with minimal "production" and transmission operations—we have determined that the A&G allocation approach is not necessary for the purpose of calculating gas distribution sector TFP growth. Instead, in this study we assume that all A&G expenses pertain to the distribution of gas to customers. We define OM&A expense as the sum of O&M expenses and A&G expenses.

Capital

Because capital is purchased in one period and used over a number of years, the price and quantity of capital input for a given year over the lifetime of a capital asset must be inferred. The quantity of capital is derived from a perpetual inventory equation, while the price of capital input is derived from an "implicit rental price" equation.

Quantity of Capital Input

The quantity of capital stock is determined by the perpetual inventory equation. The perpetual inventory equation constructs an end-of-year capital stock from the capital stock at the end of the previous year, the quantity of capital stock additions during the year, and the quantity of capital stock retirements during the year. Capital stock retirements are determined through the one hoss shay model.[63] The basic assumption underlying the one hoss shay model is that an asset provides a constant level of services (i.e., capital input) over the lifetime of the asset. In other words, an asset's efficiency or ability to provide productive services[64] does not deteriorate as the asset ages.[65]

Using the variable K to represent the end-of-year capital stock, I to represent the quantity of additions during the year, and R to represent the quantity of retirements during the year, the perpetual inventory equation has the form:

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63 As with the electric distribution studies approved in D.P.U. 17-05 and D.P.U. 18-150, the one-hoss-shay efficiency decay method is appropriate for gas distribution. The Department also accepted the one-hoss-shay methodology in the gas proceedings D.P.U. 19-120 and D.P.U. 20-120.

64 A decline in an asset's efficiency or ability to provide productive services is defined as *economic depreciation*. This is not to be confused with the accounting or financial concept of depreciation which relates to the write-off or decline in financial value of an asset over its lifetime.

65 This does not preclude increased maintenance to preserve an asset's productive services as the asset ages. However, any increased maintenance will be reflected in O&M expenses.

$$K_t = K_{t-1} + I_t - R_t$$

To estimate the quantity of additions during the year, we divide distribution additions to plant in service by the Producer Price Index for construction materials. To estimate the quantity of retirements during the year, we divide distribution retirements from plant in service by an appropriately lagged value of the Producer Price Index for construction materials. We use a lag of 51 years. This lag represents the approximate average age of assets as they were retired over the course of the study period.[66]

Because the perpetual inventory equation is a recursive equation, it is necessary to estimate a "benchmark value" of K for an early year. As the only information available to construct a benchmark value is the book value of plant and equipment, which is made up of assets of different vintages, one can only approximate the quantity of capital stock from the book value. To improve precision of the capital stock estimates for the years in the TFP growth study, it is useful to select a benchmark year that is well before the beginning of the study period. The earliest year for which plant-in-service data was widely available in the S&P Global database was 1998, so this is the year we used. The capital stock in 1998 is determined by dividing the gross book value of distribution plant in 1998 by an appropriate weighted average of Producer Price Index values for 1998 and previous years.

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66 To calculate the average service life of distribution plants among gas distribution utilities, we augmented the average service life study filed by CA Energy Consulting under Docket D.P.U. 20-120, with three additional depreciation studies from companies in our sample in an effort to confirm that a 51-year average service life was a reasonable assumption.

Using the variable PPI to represent the Producer Price Index, the mathematical formula to construct the benchmark value is as follows. This is a triangularized weighted average of the price index, which places more weight on construction prices in recent years.

$$K_{1998} = \frac{GrossDistributionPlantInService}{\sum_{i=1}^{51}\left[i \cdot PPI_{1947+i} \big/ \left(\sum_{i=1}^{51} i\right)\right]}$$

Price of Capital Input

The price of capital input is the implicit rental price that corresponds to the assumptions underlying the perpetual inventory equation described above. The price of capital input is based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime. This relationship is called the implicit rental price formula.

The implicit rental price formula has the following mathematical representation.

$$p_t^s = \frac{1-uz}{1-u}(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^{51}\right]^{-1} PPI_{t-1}$$

The variable u represents the corporate profits tax rate, the variable z represents the present value of tax depreciation charges on one dollar of investment in distribution plant and equipment, the variable r represents the forward-looking cost of capital, and the variable i represents the forward-looking inflation rate. The number 51 is the price formula represents the asset life used in the perpetual inventory equation.

Based on tax law, we use a federal corporate tax rate of 35 percent for u, adjusted to 21 percent after 2017, adding state tax to this value, and we compute z using the sum-of-years digit method.

In some applications of the implicit rental price formula, the current year's cost of capital and inflation rate are used as proxies for the forward-looking rates. This can produce substantial year-to-year variation in the implicit rental price, making it difficult to determine the trend in input price growth. An alternative that has been previously employed and produces a more stable input price series is to assume that investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time.[67] We apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2009 to 2023 period. The average cost of capital is based on the Moody's Seasoned Baa Corporate Bond Yield, published by the Federal Reserve Bank of St. Louis.[68] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[69]

Total Input

We construct the quantity index of total input for each firm and each year by using the multilateral Tornqvist indexing procedure.[70] The multilateral Tornqvist index has the form:

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67 For example, the Australian Bureau of Statistics has employed this method in its measurement of capital. See W.E. Diewert, "Issues in the Measurement of Capital Services, Depreciation, Asset Price Changes, and Interest Rates," in C. Corrado, J. Haltiwanger, and D. Sichel, eds. *Measuring Capital in the New Economy* (University of Chicago Press, 2005), at 491.

68 FRED Economic Data, Federal Reserve Board of St. Louis (https://fred.stlouisfed.org/series/BAA)

69 Bureau of Labor Statistics, Consumer Price Index for all Urban Consumers, Series ID CUUR0000SA0 (http://www.bls.gov/cpi/).

70 The multilateral Tornqvist index was developed in D.W. Caves, L.R. Christensen, and W.E. Diewert, "Multilateral Comparisons of Output, Input, and Productivity Using Superlative Index Numbers," *The Economic Journal*, Vol. 92, 1982, at 73-86.

$$ln(X_{i,t}) = .5 \cdot \sum_{j=1}^{3} (sy_{jit} + \overline{sy_j}) \cdot (lnX_{jit} - \overline{lnX_j})$$

Where

i = firm (i = 1 … 86)

t = period (t = 2009 … 2023)

j = input (j = 1 … 3)[71]

$X_{i,t}$ = the quantity of total input for firm i in period t

X_{jit} = the quantity of input j for firm i in period t

sy_{jit} = the cost share of input j for firm i in period t

A bar above a variable represents the average value over all firms and all years.

Similarly, the price of total input is computed as a multilateral Tornqvist index of the prices of the individual inputs. The index formula has the form:

$$ln(P_{i,t}) = .5 \cdot \sum_{j=1}^{3} (sy_{jit} + \overline{sy_j}) \cdot (lnP_{jit} - \overline{lnP_j})$$

Where

i = firm (i = 1 … 86)

t = period (t = 2009 … 2023)

j = input (j = 1 … 3)[72]

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[71] As described above, the inputs are distribution labor, materials, and capital.

[72] Once again, the inputs are distribution labor, distribution materials, and capital.

$P_{i,t}$ = the price of total input for firm i in period t

P_{jit} = the price of input j for firm i in period t

sy_{jit} = the cost share of input j for firm i in period t

A bar above a variable represents the average value over all firms and all years.

Total Output Growth, Total Input Growth, TFP Growth, and Total Input Price Growth

Once the quantity of output, the quantity of total input, and the price of total input is computed for each firm and each year, one can determine the industry rates of growth. In computing industry rates of growth, each firm is weighted by its relative number of customers. Denoting the number of customers by CUST, the weighting factors for each firm are computed as follows:

$$s_i = \frac{CUST_{it}}{\sum_i CUST_{it}}$$

The industry rate of total output growth for the RPC measure of TFP is then derived from the following formula:

$$ln\left({}^{Y_t}/_{Y_{t-1}}\right) = \sum_i s_i \cdot ln\left({}^{CUST_{it}}/_{CUST_{i,t-1}}\right)$$

Where Y_t signifies the output growth of the sample in year t. The industry rate of total input growth is likewise computed using the formula:

$$ln\left({}^{X_t}/_{X_{t-1}}\right) = \sum_i s_i \cdot ln\left({}^{X_{it}}/_{X_{i,t-1}}\right)$$

The industry rate of total input price growth is computed using the formula:

$$ln\left({P_t}/{P_{t-1}}\right) = \sum_i s_i \cdot ln\left({P_{it}}/{P_{i,t-1}}\right)$$

Lastly, the industry rate of RPC TFP growth is the difference between the industry rate of total output growth (given by the growth in customers) and the industry rate of total input growth:

$$\ln\left({TFP_t}/{TFP_{t-1}}\right) = \ln\left({Y_t}/{Y_{t-1}}\right) - \ln\left({X_t}/{X_{t-1}}\right)$$

Sample and Data Sources

The Northeast sample consists of 31 companies in Massachusetts, New York, Pennsylvania, Connecticut, New Hampshire, New Jersey, and Vermont. The EIA Form 176 provided customer count data for most of these companies. At the time of filing, 2024 EIA 176 data was not available, which is why our analysis ends in 2023. In cases where the EIA did not have customer count data available, we used S&P Global to fill in missing data. S&P Global served as the primary source of input data. In a limited number of observations, gaps existed in the S&P Global data. To fill these holes in the data, we obtained annual filings from state commissions. If data was missing after this process, we interpolated gaps using surrounding data. Table A.2, below, shows the companies included in the study, with an asterisk indicating which companies were included in the Northeast sample.

Table A.2
List of Companies in Sample

Arkansas Oklahoma Gas Corp.	Niagara Mohawk Power Corporation*
Atlanta Gas Light Company	North Shore Gas Company
Avista Corporation	Northern Illinois Gas Company
Baltimore Gas and Electric Company*	Northern Indiana Public Service Company
Bay State Gas Company*	Northern States Power Company
Berkshire Gas Company*	Northwest Natural Holding Company
Black Hills Energy Arkansas, Inc.	NSTAR Gas Company*
Bluefield Gas Company	Ohio Gas Company
Boston Gas Company*	Ohio Valley Gas Corporation
Brooklyn Union Gas Company*	Oklahoma Natural Gas Company
Cascade Natural Gas Corporation	Orange and Rockland Utilities, Inc.*
Central Hudson Gas & Electric Corporation*	Pacific Gas and Electric Company
Chattanooga Gas Company	PECO Energy Co.*
Citizens Gas Fuel Company	Peoples Gas Light and Coke Company
Columbia Gas of Kentucky, Incorporated	Peoples Gas System
Columbia Gas of Maryland, Incorporated	Philadelphia Gas Works Co.*
Columbia Gas of Ohio, Inc.	Pike County Light and Power Company*
Columbia Gas of Pennsylvania, Inc.*	Pike Natural Gas Co
Columbia Gas of Virginia, Incorporated	Public Service Company of North Carolina, Incorporated
Connecticut Natural Gas Corporation*	Public Service Electric and Gas Company*
Consolidated Edison Company of New York, Inc.*	Puget Sound Energy, Inc.
Consumers Energy Company	Questar Gas Company
Corning Natural Gas Corporation*	Rochester Gas and Electric Corporation*
Delta Natural Gas Company, Inc.	San Diego Gas & Electric Company
DTE Gas Company	Sierra Pacific Power Company
Duke Energy Kentucky, Inc.	South Jersey Gas Company*
Duke Energy Ohio, Inc.	Southern California Gas Company
Fillmore Gas Company, Inc.*	Southern Connecticut Gas Company*
Fitchburg Gas and Electric Light Company*	Southern Indiana Gas and Electric Company
Hope Gas, Inc.	Spire Mississippi Inc.
Illinois Gas Company	Spire Missouri Inc.
Indiana Gas Company, Inc.	St. Joe Natural Gas Co, Inc.
Kansas Gas Service Company, Inc.	St. Lawrence Gas Company, Inc.*
KeySpan Gas East Corporation*	Superior Water, Light and Power Company
Liberty Utilities (EnergyNorth Natural Gas) Corp.*	The East Ohio Gas Company
Louisville Gas and Electric Company	UGI Penn Natural Gas, Inc.*
Madison Gas and Electric Company	Vermont Gas Systems, Inc.*
Midwest Natural Gas Corporation	Virginia Natural Gas, Inc.
Midwest Natural Gas, Inc.	Washington Gas Light Company
Mountaineer Gas Company	Wisconsin Gas LLC
National Fuel Gas Distribution Corporation*	Wisconsin Power and Light Company
New Jersey Natural Gas Company*	Wyoming Gas Company
New York State Electric & Gas Corporation*	Yankee Gas Services Company*

TFP and Input Price for the U.S. Economy

The Gross Domestic Product Price Index ("GDP-PI")[73] is a comprehensive measure of output prices in the U.S. economy. Changes in the GDP-PI over time are driven by changes in input prices for the U.S. economy and changes in Total Factor Productivity in the U.S. economy. Using W_E to represent input prices for the U.S. economy and TFP_E to represent Total Factor Productivity in the U.S. economy, the percentage change in the GDP-PI is related to percentage changes in economy-wide input prices and TFP in the following way.

$$\%\Delta GDP\text{-}PI = \%\Delta W_E - \%\Delta TFP_E$$

The broadest measure of TFP for the U.S. economy is the BLS multifactor productivity index for the private business sector.[74] We use the private business sector multifactor productivity index as a proxy measure of TFP in the U.S. economy. To obtain a measure of input price changes for the U.S. economy, we rearrange terms in the above equation to obtain:

$$\%\Delta W_E = \%\Delta TFP_E + \%\Delta GDP\text{-}PI$$

Having obtained a proxy measure of TFP for the U.S. economy, we can simply calculate the percentage change in U.S. economy input prices for any given year by adding the percentage change in GDP-PI and the percentage change in U.S. economy TFP.

[73] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts, Table 1.1.4, line 1. (http://www.bea.gov/iTable/index_nipa.cfm).

[74] U.S. Department of Labor, Bureau of Labor Statistics, Multifactor Productivity for the Private Business Sector, Series ID MPU4900012 (02). (http://www.bls.gov/mfp/).

Supporting Documentation

Gas distribution TFP growth results for the Northeast sample are found in the workbook "Northeast Model" (Exhibit NG-CAEC-2 Confidential). The worksheet "RoR" shows the Moody's bond yields that were used in the analysis, the worksheet "CPI" shows the downloaded Consumer Price Index, the worksheet "Priv Biz MFP" shows the downloaded multifactor productivity index for the private business sector, the worksheet "GDP-PI" shows the downloaded GDP-PI, the worksheet "ECI" shows the downloaded Employment Cost Index, and the worksheet "PPI-Construction" shows the downloaded Producer Price Index for Construction.

The worksheet "plant_data" shows the computations of the capital stock index using the perpetual inventory equation described above, while the worksheet "Calculation" shows the other calculations that underlie the TFP results for each firm and year. In the Calculation worksheet, Columns G through M show the computation of the price, quantity, and value of labor input. Columns O through W show the computation of the price, quantity, and value of material input. Columns Y through AJ show the computation of the price, quantity, and value of capital input. Columns AL through BT show the computation of the quantity of total input that results from the application of the multilateral Tornqvist index formula. Lastly, the worksheet "TFP Summary" shows the final results.

APPENDIX B. UNIT COST BENCHMARKING RESULTS, NORTHEAST SAMPLE

Table B1: Unit O&M Cost Rankings, 2021-2023 Average			
Company	**Unit Cost**	**Score**	**Rank**
South Jersey Gas Company	77.2	-62.0%	1
Public Service Electric and Gas Company	95.3	-53.1%	2
NSTAR Gas Company	105.3	-48.1%	3
National Fuel Gas Distribution Corporation	128.3	-36.8%	4
Bay State Gas Company	152.0	-25.2%	5
New Jersey Natural Gas Company	159.7	-21.4%	6
KeySpan Gas East Corporation	160.3	-21.1%	7
Liberty Utilities (EnergyNorth Natural Gas) Corp.	163.6	-19.5%	8
Niagara Mohawk Power Corporation	165.1	-18.7%	9
PECO Energy Co.	175.8	-13.5%	10
Fillmore Gas Company, Inc.	178.4	-12.1%	11
Columbia Gas of Pennsylvania, Inc.	180.1	-11.3%	12
Brooklyn Union Gas Company	184.6	-9.1%	13
Yankee Gas Services Company	187.8	-7.5%	14
Boston Gas Company	188.1	-7.4%	15
Rochester Gas and Electric Corporation	188.5	-7.2%	16
Baltimore Gas and Electric Company	195.0	-4.0%	17
St. Lawrence Gas Company, Inc.	201.6	-0.7%	18
Philadelphia Gas Works Co.	207.6	2.2%	19
Pike County Light and Power Company	211.2	4.0%	20
Fitchburg Gas and Electric Light Company	213.4	5.1%	21
Consolidated Edison Company of New York, Inc.	217.4	7.0%	22
Southern Connecticut Gas Company	229.7	13.1%	23
Corning Natural Gas Corporation	260.9	28.5%	24
New York State Electric & Gas Corporation	281.6	38.7%	25
Central Hudson Gas & Electric Corporation	282.1	38.9%	26
Vermont Gas Systems, Inc.	285.6	40.6%	27
Orange and Rockland Utilities, Inc.	287.9	41.8%	28
UGI Penn Natural Gas, Inc.	288.8	42.2%	29
Connecticut Natural Gas Corporation	293.7	44.6%	30
Berkshire Gas Company	349.0	71.9%	31

Table B2: Unit OM&A Cost Rankings, 2021-2023 Average			
Company	**Unit Cost**	**Score**	**Rank**
Public Service Electric and Gas Company	121.2	-65.7%	1
Fillmore Gas Company, Inc.	183.6	-48.1%	2
PECO Energy Co.	237.4	-32.9%	3
National Fuel Gas Distribution Corporation	239.9	-32.2%	4
Rochester Gas and Electric Corporation	248.1	-29.8%	5
South Jersey Gas Company	248.2	-29.8%	6
NSTAR Gas Company	251.4	-28.9%	7
Liberty Utilities (EnergyNorth Natural Gas) Corp.	275.8	-22.0%	8
Niagara Mohawk Power Corporation	288.5	-18.4%	9
Vermont Gas Systems, Inc.	289.4	-18.2%	10
UGI Penn Natural Gas, Inc.	290.9	-17.7%	11
Consolidated Edison Company of New York, Inc.	310.4	-12.2%	12
Baltimore Gas and Electric Company	332.5	-6.0%	13
New Jersey Natural Gas Company	337.4	-4.6%	14
Bay State Gas Company	339.8	-3.9%	15
Southern Connecticut Gas Company	349.2	-1.3%	16
KeySpan Gas East Corporation	349.4	-1.2%	17
Philadelphia Gas Works Co.	352.5	-0.3%	18
Boston Gas Company	365.1	3.2%	19
Columbia Gas of Pennsylvania, Inc.	376.2	6.4%	20
New York State Electric & Gas Corporation	376.9	6.6%	21
Yankee Gas Services Company	381.9	8.0%	22
Brooklyn Union Gas Company	403.9	14.2%	23
Connecticut Natural Gas Corporation	414.7	17.3%	24
Pike County Light and Power Company	449.0	26.9%	25
Orange and Rockland Utilities, Inc.	475.0	34.3%	26
Fitchburg Gas and Electric Light Company	485.5	37.3%	27
Berkshire Gas Company	500.1	41.4%	28
Central Hudson Gas & Electric Corporation	503.9	42.5%	29
St. Lawrence Gas Company, Inc.	576.9	63.1%	30
Corning Natural Gas Corporation	608.9	72.2%	31

Table B3: Unit Total Cost Rankings, 2021-2023 Average			
Company	**Unit Cost**	**Score**	**Rank**
Fillmore Gas Company, Inc.	317.8	-51.2%	1
Vermont Gas Systems, Inc.	367.9	-43.5%	2
Public Service Electric and Gas Company	430.2	-33.9%	3
National Fuel Gas Distribution Corporation	441.4	-32.2%	4
Rochester Gas and Electric Corporation	443.6	-31.9%	5
Pike County Light and Power Company	536.2	-17.7%	6
Niagara Mohawk Power Corporation	550.8	-15.4%	7
Baltimore Gas and Electric Company	556.8	-14.5%	8
New Jersey Natural Gas Company	558.4	-14.3%	9
South Jersey Gas Company	575.4	-11.6%	10
NSTAR Gas Company	576.1	-11.5%	11
PECO Energy Co.	604.3	-7.2%	12
Bay State Gas Company	604.7	-7.2%	13
Liberty Utilities (EnergyNorth Natural Gas) Corp.	620.2	-4.8%	14
Southern Connecticut Gas Company	625.6	-3.9%	15
New York State Electric & Gas Corporation	652.2	0.1%	16
Philadelphia Gas Works Co.	662.2	1.7%	17
Columbia Gas of Pennsylvania, Inc.	662.2	1.7%	18
Brooklyn Union Gas Company	675.0	3.7%	19
Boston Gas Company	694.8	6.7%	20
UGI Penn Natural Gas, Inc.	702.7	7.9%	21
Connecticut Natural Gas Corporation	723.8	11.1%	22
KeySpan Gas East Corporation	735.8	13.0%	23
Consolidated Edison Company of New York, Inc.	783.4	20.3%	24
Corning Natural Gas Corporation	824.3	26.6%	25
Yankee Gas Services Company	841.9	29.3%	26
Berkshire Gas Company	858.7	31.9%	27
Orange and Rockland Utilities, Inc.	866.7	33.1%	28
Central Hudson Gas & Electric Corporation	889.1	36.5%	29
St. Lawrence Gas Company, Inc.	892.7	37.1%	30
Fitchburg Gas and Electric Light Company	913.5	40.3%	31

APPENDIX C. ECONOMETRIC COST BENCHMARKING STUDY

Introduction

There are two approaches to cost benchmarking for distribution utilities. The first is unit cost benchmarking, which compares the cost per unit of output from one company against a set of peer companies, where the peer companies could be a National sample, a regional sample, or a specific set of peers, selected based on criteria chosen by the analyst. A key drawback of this approach is that the results depend heavily on the sample of peer utilities, since the study itself merely compares average costs and does not control for company characteristics beyond the selection of the peers. Nevertheless, the method has the benefit of simplicity and in some cases may be the best option in light of data limitations. Massachusetts companies operating under PBR have employed this method for unit cost benchmarking in prior proceedings.

The other general form of cost benchmarking is an econometric approach, which attempts to resolve, through regression analysis, the problem of reliance on peer companies that may have substantially different operating conditions than the particular utility in question. This approach takes data from a sample of companies over time and uses statistical methods to determine how the explanatory variables impact utility costs. The theory behind the econometric approach is that the choice of peer utilities matters less if a regression model can account for differences across companies using variables that explain the cost drivers of each company. Variables like population density and capital investment initiatives related to infrastructure age can control for legitimate cost-related differences between companies that are largely outside of the company’s control. The results of the regression approach can be interpreted the same way as the unit cost benchmarking approach because it asks the same question: how do the company's costs compare with the average costs of a peer group? The difference between this approach and the simple unit cost approach is that the regression approach adjusts the results of the peer group to more accurately account for important cost-driving dimensions observed in the data.

Through the inclusion of explanatory variables, an econometric approach may improve the accuracy of a benchmarking analysis. However, this regression technique can present a false sense of scientific certainty about a utility's cost efficiency. The econometric approach assumes that the variables chosen for the model fully explain the utility's cost drivers. If a variable that drives cost is not included in the regression model, the company will appear to perform differently from the model's prediction because the model has an omitted variable bias. For example, suppose a utility finds it necessary to make significant updates to its Information Technology infrastructure as a result of its unique cybersecurity concerns. Then compared to peers, this company might appear highly cost-inefficient if the model contains no explanatory variable associated with this investment. In reality, the company may be just as operationally efficient as its peers, but experiences ongoing costs beyond its control that are not explained by the variables in the model. Any variable, if excluded from the regression model, may skew the results in this manner. This is the key challenge in cost benchmarking.

Data

To perform the econometric benchmarking analysis, data on cost, output, and operating conditions are required for a sample of utilities. The sample, output, and cost variables are drawn from the

TFP study.[75] The O&M cost measure used in this study is taken from the TFP study.[76] For a company *i* in year *t*, OM&A and total cost are defined as

$$OM\&A_{i,t} = O\&M_{i,t} + A\&G_{i,t}$$

$$Capital\ Cost_{i,t} = K_t * p_t^s$$

$$Total\ Cost_{i,t} = OM\&A_{i,t} + Capital\ Cost_{i,t}$$

We collect data on utility operating conditions from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and ArcGIS Hub. From the PHMSA, we collect total miles of mains, miles of unprotected bare steel mains, and miles of cast iron mains. These data allow us to construct a company's total miles of leak-prone pipe, which we define as its miles of unprotected bare steel mains plus its miles of cast iron mains. Of particular interest is a company's share of leak-prone pipe, which we define as its miles of leak-prone pipe divided by its total miles of mains. We expect that it is (1) costlier to maintain a distribution network comprised of a higher share of leak-prone pipe due to higher maintenance costs; and (2) costly to reduce this share through capital replacement projects.

From ArcGIS Hub, we collect data on each company's service territory area to measure population density. We expect that it may be costlier for companies to operate in more urban areas.

[75] See Appendix A for details on the utility sample and cost definitions.

[76] To avoid penalizing companies that own storage plant in the model, this is controlled for by removing storage expenses from plant and O&M.

Results

For each model, real (inflation-adjusted) costs are expressed as a function of total customers, population density, leak-prone pipe miles as a share of total mains miles, the cumulative change in the share of leak-prone pipe miles since 2009, and year indicator variables that captures cost trends common to all companies, like the impact of the COVID-19 pandemic on costs. The input price index is subtracted from total cost so that the left-hand side represents real inputs, allowing us to control for input prices without estimating a coefficient.[77] The cumulative change in the share of leak-prone pipe miles is included given that infrastructure replacement projects involve capitalized costs that continue to impact the company's total cost while that capital is in service.

The model is estimated using our National sample, but we remove companies with very small customer counts or miles of leak-prone pipe.[78] The model estimates can be found in Table C1, below. The coefficients can be interpreted in terms of percentage effects and have the expected signs. For instance, a coefficient of 0.842 on total customers implies that a one percent increase in total customers leads to a 0.842 percent increase in total cost, all other variables held constant. Population density, share of leak-prone pipe miles, and the cumulative reduction in the share of leak-prone pipe miles all positively impact total cost, as expected.

[77] Economic theory states that a one percent increase in input prices leads to a one percent increase in cost. This restriction is imposed in the models by this normalization. Input prices are controlled for in the model through the normalization.

[78] Specifically, we remove companies that are in the bottom 10th percentile for either average total customers or average total miles of leak-prone pipe. The results are not particularly sensitive to the chosen percentile, but because Boston Gas is in the 77th percentile in total customers and the 98th percentile in miles of leak-prone pipe, it is important to remove companies that are anomalous along these dimensions so that the results are not confounded by outliers that bear little resemblance to Boston Gas.

Table C1: Cost Model Coefficients

Variable	Total Cost		OM&A		O&M	
	Coefficient	Standard Error	Coefficient	Standard Error	Coefficient	Standard Error
Total Customers	0.842	0.008	0.825	0.011	0.831	0.011
Population Density	0.092	0.007	0.049	0.010	0.041	0.010
Share of Leak-Prone Pipe Miles	0.463	0.076	0.739	0.117	0.995	0.113
Cumulative Reduction in Share of Leak-Prone Pipe Miles	1.388	0.215	0.951	0.333	0.337	0.428
R^2	0.951		0.915		0.917	
Observations	694		694		694	

Year fixed effects are included. Standard errors are robust to heteroskedasticity.