COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00	)	D.P.U. 22-22

JOINT DIRECT TESTIMONY OF

MARK E. MEITZEN, PH.D.
NICHOLAS A. CROWLEY, MS

Performance-Based Ratemaking Mechanism

On behalf of

NSTAR Electric Company
d/b/a Eversource Energy

January 14, 2022

PRE-FILED DIRECT TESTIMONY

OF

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I. INTRODUCTION

Q. Dr. Meitzen and Mr. Crowley, please state your full names and business address.

A. Our names are Dr. Mark E. Meitzen and Mr. Nicholas A. Crowley. Our business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q. On whose behalf are you submitting this testimony?

A. In this proceeding, we are testifying on behalf of NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric," "Eversource" or the "Company").

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

A. I am a Senior Consultant with Christensen Associates. Christensen Associates is an economic research and consulting firm with expertise in the design and application of incentive regulation plans across a number of network industries and with 40 years of experience in utility industries.

Q. Would you please summarize your educational background and business experience?

A. I have a Bachelor of Science degree in economics from the University of Wisconsin-Oshkosh and a Master of Science from the University of Wisconsin-Madison. I received my Ph.D. in economics from the University of Wisconsin-Madison. I have been at Christensen Associates since 1990. Prior to that, I was a regulatory economist at Southwestern Bell Telephone Company (now AT&T) in St. Louis, Missouri, and I was a member of the economics faculty at the University of Wisconsin–Milwaukee and Eastern Michigan University. Among my various duties at Christensen Associates, I have consulted with firms in several network industries, including the telecommunications, electricity, postal and railroad industries. I have consulted with these industries on a variety of issues including incentive regulation, productivity, costing and pricing. I have also sponsored testimony on these issues in regulatory proceedings.

I have co-authored a number of other productivity studies conducted by Christensen Associates, including a recent study prepared on behalf of EPCOR in Alberta, Canada and productivity analysis on behalf of AT&T, which was filed with the Federal Communications Commission. I have also performed numerous analyses for former regional Bell Operating Companies, the United States Telephone Association, the National Cable Television Association, and all the major telecommunications companies in Canada. I have analyzed incentive regulation issues for various network industries including the telecommunications, electric utility and postal industries. I also directed the Christensen Associates team that analyzed incentive-regulation options for the privatization of Peru's telecommunications industry.

Among the articles and reports that I have written, I have recently co-authored three articles on PBR in the electric utility industry (including one with Mr. Crowley).[1] I have also published articles on total factor productivity, incentive regulation in network industries (electricity, gas, and telecommunications) and cross-subsidization issues in the electric utility industry. I am a principal author of a study of U.S. railroad competition issues commissioned by the U.S. Surface Transportation Board. My curriculum vitae is attached as Exhibit ES-PBR/TFP-2.

Q. Have you previously testified before the Department of Public Utilities or other regulatory commission?

A. Yes, I have. I have sponsored a total factor productivity study and testified on performance-based ratemaking ("PBR") issues in three proceedings before the Massachusetts Department of Public Utilities (the "Department") on behalf of Boston Gas Company and the former Colonial Gas Company d/b/a National Grid (together, "Boston Gas") in D.P.U. 20-120;[2] on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (together, "Mass. Electric") in D.P.U. 18-150;[3] and,

1 Nick Crowley and Mark Meitzen, "Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities," *Utilities Policy*, 72 (2021); 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; and Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, 31 (2018) 39-46.

2 Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

3 Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, November 15, 2018; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, April 22, 2019.

on behalf of NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy in D.P.U. 17-05 (together, "NSTAR Electric").[4]

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

A. I am a Senior Economist with Christensen Associates.

Q. Would you please summarize your educational background and business experience?

A. I have a Bachelor of Science in economics, as well as a Master of Science in economics from the University of Wisconsin-Madison. I began working at Christensen Associates 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 incentive regulation of oil pipelines under Docket RM15-20,[5] 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, vis-à-vis the development of cost benchmarks for power systems and in marginal cost estimation and the development of marginal cost models filed before regulatory authorities in the United States and Canada. I have recently co-authored an article with Dr. Meitzen on the impact

4 Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 17-05, January 17, 2017; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., Dennis L. Weisman, Ph.D., and Carl G. Degen, D.P.U. 17-05, May 19, 2017.

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

of price-cap regulation on Canadian electricity distribution utilities.[6] My curriculum vitae is attached as Exhibit ES-PBR/TFP-3.

Q. Mr. Crowley, have you previously testified before the Department or other state regulatory commission?

A. I recently testified with Dr. Meitzen on behalf of Boston Gas Company and the former Colonial Gas Company each d/b/a National Grid in D.P.U. 20-120.[7] I also calculated total factor productivity measures for the electricity sector and developed indexes for use in performance-based ratemaking in proceedings before the Department on behalf of Mass. Electric in D.P.U. 18-150[8] and on behalf of NSTAR Electric in D.P.U. 17-05.[9]

Q. What is the purpose of your testimony?

A. The purpose of this joint testimony is to present the total factor productivity ("TFP") and *X* factor calculations for use in Eversource's proposed second-generation PBR plan. In this testimony, we briefly discuss the revenue cap formula currently used in the Company's PBR plan and then present the results of our study of productivity designed to be used for

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[6] Nick Crowley and Mark Meitzen, "Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities," *Utilities Policy,* 72 (2021).

[7] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

[8] Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, November 15, 2018; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, April 22, 2019.

[9] Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 17-05, January 17, 2017; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., Dennis L. Weisman, Ph.D., and Carl G. Degen, D.P.U. 17-05, May 19, 2017.

a revenue cap. Based on the results of this productivity study, we present the *X* factor results for the Company's revenue cap.

II. THE EVERSOURCE REVENUE CAP FORMULA

A. The Benefits of PBR

Q. In general, why is PBR viewed as an improved form of economic regulation relative to cost of service regulation?

A. Many forms of regulation, including the Eversource revenue cap, fall under the umbrella of PBR or incentive regulation.[10] PBR is generally a form of regulation that provides the regulated firm with stronger incentives for efficiency than traditional cost of service ("COS") regulation. Typically, there are also efficiencies in the operation of the regulatory process under PBR. In principle, these incentives lead to more efficient firm behavior, efficiency in the regulatory process, and resulting benefits for all stakeholders, including customers of the regulated firm.

Q. What is the source of the stronger incentives provided by PBR?

A. Under PBR in the electric utility industry, the utility is allowed the flexibility to pursue cost reduction initiatives and to keep the benefit of those reductions until rates are reset in the future, whereas under COS regulation the expectation is that more routine rate-setting

[10] "Incentive regulation can be defined as the implementation of rules that encourage a regulated firm to achieve desired goals by granting some, but not complete, discretion to the firm." David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume. 9, 1994, p. 246.

processes will occur and that the return earned by the firm will be more consistently aligned with its authorized return.[11]

The strength of these PBR incentives depends on the form of PBR and how much of the cost savings the firm is allowed to retain. For example, under an earnings sharing mechanism, the firm is allowed to retain earnings above the authorized return on equity ("ROE") up to a certain point—e.g., 200 basis points above authorized ROE—after which, excess earnings are refunded to customers. Consequently, the firm has a strong profit motive to become more efficient up to the full sharing point. Above that point, the PBR plan operates much like traditional COS regulation. On the other hand, a cap or ceiling type of incentive regulation, such as price caps or revenue caps, generally provides stronger incentives for efficient behavior. In the purest form, these types of incentive regulation mechanisms set a cap or ceiling on prices or revenues with no constraint on earnings or requirements for sharing, giving the firm the strongest incentive to reduce costs and increase profits.[12]

[11] It is generally recognized that regulatory lag can provide some incentive for efficient behavior under COS of service regulation because the dollar saved is not instantaneously returned to ratepayers. The longer the period of time over which the firm can retain its cost savings, the stronger the incentives for efficient behavior, holding all other factors constant. Quality of service is also an important consideration, as unconstrained cost cutting could lead to service degradation. Also, as discussed below, under most price cap plans, the firm has the incentive to increase output (up to the profit-maximizing point), which may work at cross purposes with conservation goals.

[12] However, in most cases, even the pure form of cap regulation requires that cast-off rates be just and reasonable and that rates be trued up to costs at the time of plan reviews (typically a five-year period).

Q. Are there not increased risks associated with PBR mechanisms?

A. There could be, depending on the structure of the PBR mechanism. The regulated firm faces greater risks under PBR under circumstances where earnings are allowed to fall below the authorized rate of return and, subject to the particular rules of the regulatory plan, the firm has no recourse to obtain or appeal for relief. Under a strict form of earnings sharing, there is typically a lower bound on earnings—e.g., 200 basis points—that the firm must live with before obtaining rate relief or triggering a rate case reopener.[13] With a pure cap form of regulation, just as there is no constraint on earnings above the authorized rate of return, absent conditions that allow for a rate case reopener in extreme circumstances, there is no automatic relief available to the firm for earnings less than the authorized rate of return. In one respect, these risks can be thought of in terms of an added incentive to the firm to perform well because it is effectively "operating without a net."

Q. Are there other efficiencies derived from PBR?

A. There are a number of potential regulatory cost savings for both the firm and the regulator. In general, many of the types of filings and/or proceedings that are required outside of a PBR plan may no longer be required or the period between such activities may be extended, saving resources for both. Examples of potential regulatory savings include expedited procedures for annual compliance filings and investment decisions, and an extended time

[13] Other forms of earnings sharing taper the amount of earning above authorized ROE the firm must refund (or the amount of rate relief for earnings below authorized ROE). For example, regarding refunds for earnings above authorized ROE, the firm may keep all earnings for 200 basis points above authorized ROE, refund 50 percent of earnings between 200 to 300 basis points above authorized ROE, and refund all earnings greater than 300 basis points above authorized ROE.

frame between rate cases. From the firm's perspective, these regulatory efficiencies allow the firm to devote resources previously dedicated to regulatory efforts to be redirected to the more efficient operation of the company. For example, if there is not a mandated capital cost recovery process and the regulated firm is able to conduct its investment activity on a more flexible basis, firm engineering resources that would otherwise be devoted to supporting capital recovery applications can be redeployed to more productive activities.

Q. What benefit do the firm's customers realize from PBR?

A. One of the fundamental principles of PBR is that customers share in the benefits of incentive regulation. These benefits may occur contemporaneously during the operation of the plan (i.e., *ex ante* benefits) or after the fact (i.e., *ex post* benefits). *Ex ante* benefits would include slower rate escalation and stability of rates compared to alternative COS-based forms of regulation. *Ex post* benefits would include consumers reaping the fruits of more efficient firm behavior and efficiencies in the regulatory process through earnings sharing and rebasing of rates at the time the plan is reviewed.[14] In addition, the firm may be able to invest more efficiently under incentive regulation compared to traditional COS and these investments may generate further efficiencies that flow through to customers and may also result in higher quality of services.

[14] Typically, incentive regulation plans such as price cap plans are subject to a comprehensive review after a pre-determined number of years of operation—e.g., five years.

B. Revenue Caps and the Revenue Decoupling Mechanism

Q. What type of indexed cap formula is Eversource proposing?

A. As with its first-generation plan, Eversource is proposing to implement a revenue cap in the proposed PBR Plan to enable annual adjustments to its base distribution revenue target collected in conjunction with the Revenue Decoupling Mechanism ("RDM"). Both revenue per customer and revenue caps have been used in Massachusetts and are viewed as mechanisms that better align the firm's incentives with desired conservation goals while still maintaining the efficiency properties of the cap approach.[15] Revenue per customer and revenue caps allow prices and revenues to increase as output declines and are more consistent with other policy goals, such as conservation efforts, than price caps as the firm has a greater ability to counteract the effects of declining output.[16] Revenue per customer and revenue caps are also consistent with revenue decoupling as targeted revenues (and not prices) are indexed by the cap.

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15 In D.P.U. 07-50-A, the Department noted that (at 50):

> We recognize that circumstances will vary from company to company and, as such, we will permit a certain amount of flexibility when establishing a revenue requirement for a distribution company. Such ratemaking proposals could be similar in structure to the PBR rate plans that most electric and gas companies have in place today.

16 In contrast, subject to profit maximizing conditions, under price caps the firm has the incentive to increase output. At the very least, because prices are capped and revenue would decline as output declines, the firm has a disincentive to discourage output growth under price caps. Thus, price cap regulation can work at cross-purposes with conservation goals. Furthermore, because prices are capped rather than revenues, price cap regulation is not entirely consistent with revenue decoupling.

Q. How does the Eversource PBR revenue cap work in conjunction with the RDM?

A. To recover the base distribution revenue target through the RDM, actual revenue would be compared to the distribution target revenue at the end of the year, and the difference would be allocated to each rate class and divided by forecast sales to produce a unit rate per kWh for each class. This unit rate constitutes the revenue-decoupling adjustment factor ("RDAF"), which is applied to billed kWh on customer bills during the subsequent year. This amount will be either a credit or debit, depending on whether actual revenue is greater than or less than the distribution revenue target in the prior year.

Our understanding is that the RDM and/or RDAF is independent of the PBR indexing mechanism and does not operate to modify the amount of revenue allowed for collection through base distribution rates or the PBR mechanism adjustments in any year. However, in a given year, the distribution annual revenue target ("ATR") will change in accordance with the PBR indexing formula (i.e., the revenue cap), and the RDM will be adjusted to recover the new distribution revenue target determined by the PBR indexing mechanism. The new, PBR indexing mechanism would be put in place as of January 1, 2023, with the first annual rate adjustment taking effect January 1, 2024.

Q. Is it your opinion that the Eversource PBR Plan should be extended as proposed for a second generation?

A. Yes. As Dr. Kaufmann demonstrates, Eversource and its customers benefitted from Eversource's performance under its first-generation PBR plan.[17]

C. Revenue Cap PBR Mechanism

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

A. A revenue cap formula sets a ceiling for the rate of change for base distribution revenues. This cap or ceiling restricts rates of change in revenues to be at or below the cap. The cap is based on some measure of economic performance that is external to the regulated firm and cannot be manipulated by the firm (i.e., exogenous). Generally, the cap has the general form of "$I - X$," where I is a measure of inflation and X is a productivity-based offset to the inflation measure. The specification of X depends on how I is specified – that is, X is a function of I, or $X = X(I)$.[18]

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17 Testimony of Company Witness Dr. Lawrence R. Kaufmann, Exhibit ES-PBR/PLAN-1.

18 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. See, 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.

Q. Would you please describe the measure of expected industry changes in productivity used in determining the *X* factor for a revenue cap?

A. The productivity concept typically used is total factor productivity ("TFP"), which is generally defined as the ratio of total output to total input:

(1) *TFP = Total Output/Total Input*

The correct specification of output for a TFP study depends on the purpose of the study. That is, the output measure will differ depending on whether the purpose is to assess efficiency or to calibrate an indexed PBR cap. When the purpose of TFP measurement is for use in calibrating the *X* factor for a revenue cap, the proper measure of Total Output is given by the number of customers served by the relevant unit of production (e.g., a firm or an industry).[19] We define this measure of TFP as *revenue cap TFP* (RC TFP or TFP^R).

(1a) TFP^R = *Customers/Total Input*

Total input includes all resources used by the unit of production in providing those services. Typically, TFP studies divide total input into three categories: capital, labor, and materials. TFP is widely recognized as a comprehensive measure of productive efficiency because, unlike measures of partial productivity, such as labor productivity, TFP provides a measure of the contribution of all inputs used in the production of total output.

Productivity changes are measured as the percentage change in TFP, which is computed as the percentage change in total output less the percentage change in total input:

[19] In general, this is not the same measure of output that would be used in an efficiency measure of TFP.

$$(2)\ \%\Delta TFP = \%\Delta Total\ Output - \%\Delta Total\ Input$$

Or, in the case of RC TFP that is a component of a PBR *X* factor:

$$(2a)\ \%\Delta TFP^{R} = \%\Delta Customers - \%\Delta Total\ Input$$

For example, if TFP growth is equal to 2.0%, this means that the same output may be produced with 2.0% fewer inputs, or the same quantity of inputs will yield 2.0% more output. On the other hand, if TFP growth is equal to -2.0%, this means that the same output is produced with 2.0% greater inputs, or the same quantity of inputs will yield 2.0% less output.

Q. Is it true that the output measure for the version of TFP that is used in a revenue cap will differ from the output measure in an efficiency measure of TFP?

A. Yes. The proper measure of output when TFP is used in a revenue cap is customer growth, which differs from the measure of output in an efficiency measure of TFP. Typically, the output measure for a PBR cap (e.g., price cap or revenue cap) is a subset of the output measure used in an efficiency measure of TFP. Thus, alternative measures of output, such as MWh or peak load are not appropriate for a revenue cap.

Q. Would you please describe the revenue cap PBR formula?

A. In a revenue cap, allowed revenue growth is capped by the PBR index:

$$(3)\ \%\Delta R_I = (I - X)$$

The measurement of *X* is based on $\%\Delta\ TFP^R$ as described above.[20] As with other PBR cap formulas, the revenue cap provides the firm with strong incentives for more efficient behavior.

Q. What is the revenue cap formula when the *I* factor is based on GDP-PI?

A. If the *I* factor is represented by the rate of change in economy-wide output inflation as in the GDP-PI, the revenue cap *X* factor is the combination of TFP and input price differentials between the electric distribution industry and the overall economy. The TFP differential between the electric distribution industry ($\%\Delta\ TFP^R_I$) and the overall economy ($\%\Delta TFP_E$) is given by:

$$\text{(4a)}\ (\%\Delta\ TFP^R_I - \%\Delta TFP_E)$$

The input price differential between the overall economy ($\%\Delta W_E$) and the electric distribution industry ($\%\Delta W_I$) is given by:

$$\text{(4b)}\ (\%\Delta W_E - \%\Delta W_I)$$

Combining the TFP differential and the input price differential produces the *X* factor when the GDP-PI is used as the measure of the *I* factor:

$$\text{(4c)}\ X = [(\%\Delta\ TFP^R_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)]$$

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20 An important difference between a revenue per customer cap and a revenue cap is that a revenue cap does not typically allow revenue to change with customer growth. Therefore, an important feature of a revenue cap is that the Company would absorb the costs associated with additional customer growth, which can be interpreted as an implicit stretch factor in the cap equal to the rate of customer growth.

Thus, the revenue cap formula when the *I* factor is the GDP-PI is given by:

(4d) $\%\Delta R = GDP\text{-}PI - [(\%\Delta\, TFP^{R}_{I} - \%\Delta TFP_{E}) + (\%\Delta W_{E} - \%\Delta W_{I})]$

III. PRODUCTIVITY STUDY FOR EVERSOURCE'S REVENUE CAP

A. Overview

Q. Is your productivity study based on a model that is identical to the model presented in D.P.U. 17-05, initiating PBR for NSTAR Electric?

A. No. The basic methodology is consistent with the model presented in D.P.U. 17-05; however, we have made refinements to the model to follow the Department's directives in prior PBR proceedings conducted in Massachusetts.

Q. What are the refinements that you have introduced to the model since the D.P.U. 17-05 proceeding?

A. We have made two refinements to the model since the D.P.U. 17-05 proceeding. First, we include certain customer accounts and sales expenses, as well as a portion of administrative and general ("A&G") expenses in the computation of Total Input to assure that distribution costs typically considered in traditional ratemaking are represented in the model. Second, we use the hyperbolic model of asset efficiency decay in our estimation of capital input rather than the one hoss shay model. These two refinements are discussed in greater detail in Appendix A.

Q. Why have you elected to include customer accounts and sales in the model from a methodological perspective?

A. The goal of the TFP Study is to develop the relevant cost trends for the electric distribution industry. From a methodological perspective, this means that all costs that are related to the distribution function should be incorporated to the model. Since D.P.U. 17-05, the methodology for conducting the TFP Study has evolved to include customer accounts and sales expenses as distribution-related costs. Given the way these costs are reported in the FERC Form 1, it is a relatively straightforward exercise to incorporate these costs into the TFP model. Similarly, labor and materials expense for the selected FERC Form 1 accounts are included in the model, as these accounts can credibly be attributed to the distribution function of the utilities.

Q. Have you also incorporated Administrative & General Costs into the TFP model?

A. Yes. For the same methodological reason (i.e., incorporating distribution-related costs), we have incorporated Administrative & General ("A&G") costs into the model, although it is not as straightforward an exercise as it is with customer accounts and sales. A&G expenses are associated with activities that span the functional components of the electric utilities included in the study group, some of which continue to be vertically integrated utility companies. As a result, A&G expenses for electric utilities in the study group include costs associated with owning and operating distribution, transmission and generation assets, which means that A&G costs are not causally attributable to a particular function.

Because of the joint and common nature of A&G expenses, the assignment of a portion of A&G expenses to the distribution function requires a non-causal attribution of these expenses to the utilities' functional components. However, because joint and common expenses do not have a unique, economically causal relationship to particular functional components, economic theory does not provide an unambiguously correct or unique method to attribute these expenses to particular functions.[21] For example, although part of a CEO's time is devoted to distribution, transmission and production, respectively, how much time is causally related to each of the three functions is indeterminate.

Given the nature of joint and common costs, allocation methods must be judged and determined on *non-economic* criteria. In recognition of this fact, we have developed a conceptional basis for attribution of A&G costs to distribution operations based on practical considerations similar to those employed in traditional ratemaking approaches, rather than a strict theoretical economic basis.

Q. How have you addressed the concern regarding the absence of an economically principled approach to attributing A&G expenses to distribution operations?

A. As we stated above, the critical consideration in studying the productivity of the electric distribution function is to assure that the costs encompassed in the study are distribution related. We determined that, if properly done, the risk of generating unreliable distribution TFP and input price results could be minimized while accounting for A&G expenses in the

[21] Appendix A discusses the economic issues regarding allocations of joint and common costs.

TFP Study. As explained in Appendix A, we apportion A&G expenses using plant-in-service as an allocator, including a portion of A&G equivalent to the portion of plant-in-service. The underlying assumption is that this reasonably corresponds to the portion of A&G expenses attributable to distribution service.

Q. The methodological approach for assessing asset efficiency decay that you have used is the hyperbolic model rather than the one hoss shay model. What is the reason that you have made this methodological change?

A. The hyperbolic model of asset efficiency decay is a generalized model of decay used by the U.S. Bureau of Labor Statistics for the calculation of U.S. economy-wide multifactor productivity. The model assumes that various assets decay with a concave slope, signifying slower asset decay in early years, much like the One Hoss Shay ("OHS") model of capital decay. In fact, the OHS model, which has been accepted by the Department in previous Massachusetts filings, is a specific case of the hyperbolic model.

Whereas the OHS model assumes zero efficiency decline until asset retirement, the hyperbolic model assumes a slow initial efficiency decline, followed by a faster decline near the asset's average service life, with a tail of slow efficiency decline. The hyperbolic model allows for a given asset to reach zero efficiency before or after the average service life of the asset class, with the assumption that asset retirements follow a truncated normal distribution about the mean (average) service life. After thorough research, we determined that modeling capital decay using the hyperbolic function resulted in both a more accurate and intuitive representation of distribution capital decay, and also a more robust measure of capital stock. Thus, the hyperbolic model is a generalization and refinement of the OHS assumption accepted by the Department in previous filings.

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

A. We have performed a study of U.S. electric distribution RC TFP and input price over the 15-year period, 2006-2020, to derive the industry figures for the determination of $X(I_E)$. As in the Eversource proceeding, the 15-year period strikes a balance between using the most recent, relevant information for determining forward-looking changes in productivity and using a period long enough to account for short-term variation in results.

Although *X* is typically determined by a productivity study that, by its very nature, is based on historical information, *X* is forward-looking as it is based on those differentials that are expected to prevail over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.

We have determined results for two different samples, which are a National sample of 65 firms that represent the overall U.S. electric distribution industry and a sample of 17 firms that represent the distribution industry in the Northeast United States.[22] The comparable figures for changes in economy-wide TFP and input prices are obtained from official U.S. governments sources.

[22] Based on previous Department decisions, we have also calculated the results for a subsample of Northeast U.S. utilities. For example, in D.P.U. 96-50, the Department determined that the *X* factor should be based on regional TFP and input price growth. D.P.U 96-50 (Phase I), November 29, 1996, at 275-276.

B. Study Results

Q. How did you determine changes in electric distribution industry RC TFP and input prices?

A. Appendix A contains the methodological details of how we determined percent changes in RC TFP and input prices for the electric 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 U.S. electric distribution utilities?

A. Figure 1 provides the results for rates of change in total output, total input, RC TFP and input prices for U.S. distribution utilities over the 2006-2020 period. Recall that RC TFP = %*Δ* Output -%*Δ* Input or column 2 – column 3 = column 4.

Figure 1

RC TFP Results for National Electric Distribution Industry, 2006-2020

Period	Output	Input	RPC TFP	Input Price
2006	-	-	-	-
2007	1.10%	-2.54%	3.63%	6.87%
2008	0.64%	-0.69%	1.33%	6.33%
2009	0.08%	0.36%	-0.29%	5.64%
2010	0.38%	1.92%	-1.54%	1.92%
2011	0.36%	1.77%	-1.41%	2.99%
2012	0.52%	0.72%	-0.20%	3.40%
2013	0.80%	-2.24%	3.04%	2.96%
2014	0.60%	-0.01%	0.61%	2.89%
2015	0.77%	-0.54%	1.31%	2.37%
2016	0.89%	1.64%	-0.75%	1.86%
2017	0.92%	2.98%	-2.06%	1.58%
2018	0.68%	0.59%	0.09%	1.68%
2019	0.88%	0.95%	-0.08%	3.45%
2020	0.78%	3.67%	-2.89%	0.37%
Average	**0.67%**	**0.61%**	**0.06%**	**3.17%**

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

A. Figure 2 provides the results for rates of change in total output, total input, RC TFP and input prices for Northeast distribution utilities over the 2006-2020 period.

Figure 2

RC TFP Results for Northeast Electric Distribution Industry, 2006-2020

Period	Output	Input	RPC TFP	Input Price
2006	-	-	-	-
2007	0.78%	0.90%	-0.12%	6.33%
2008	0.47%	0.10%	0.37%	6.41%
2009	0.21%	1.30%	-1.09%	5.25%
2010	0.62%	4.08%	-3.45%	2.17%
2011	0.42%	3.18%	-2.77%	2.88%
2012	0.55%	2.25%	-1.71%	3.45%
2013	1.14%	-4.97%	6.10%	3.25%
2014	0.54%	2.60%	-2.05%	2.70%
2015	0.83%	-2.82%	3.65%	2.30%
2016	0.24%	0.26%	-0.01%	1.82%
2017	0.59%	-0.46%	1.05%	1.71%
2018	0.78%	0.37%	0.40%	5.82%
2019	0.65%	-1.11%	1.75%	3.18%
2020	0.12%	2.97%	-2.84%	-3.70%
Average	**0.57%**	**0.62%**	**-0.05%**	**3.11%**

IV. DERIVATION OF THE *X* FACTOR FOR THE EVERSOURCE REVENUE CAP

Q. Would you please generally describe your derivation of the *X* factor for the Company's revenue cap?

A. Yes. The Company is proposing to use the GPD-PI as the *I* factor, therefore, 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. What are the economy-wide results for changes in TFP and input prices over the 2006-2020 period?

A. Figure 3 provides the economy-wide results over the 2006-2020 period.

Figure 3

Economy-Wide Results, 2006-2020

Period	GDP PI	TFP	Input Price
2006	-	-	-
2007	2.66%	0.46%	3.12%
2008	1.89%	-1.13%	0.77%
2009	0.78%	0.31%	1.09%
2010	1.16%	2.62%	3.78%
2011	2.06%	-0.24%	1.82%
2012	1.91%	0.59%	2.50%
2013	1.76%	0.38%	2.14%
2014	1.86%	0.49%	2.36%
2015	1.03%	1.13%	2.15%
2016	1.08%	-0.32%	0.76%
2017	1.90%	0.52%	2.42%
2018	2.19%	0.99%	3.18%
2019	1.79%	0.72%	2.51%
2020	1.16%	-1.75%	-0.60%
Average	**1.66%**	**0.34%**	**2.00%**

Q. What is the *X* factor for the National sample of U.S. electric distribution companies?

A. Figure 4 provides the TFP and input price differentials and the resulting *X* factor using the National electric distribution sample and its baseline RC TFP and input results over the 2006-2020 period.

Figure 4

***X* Factor for the National Electric Distribution Sample**
2006-2020

	TFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
2006	-	-	-	-	-	-	-
2007	3.63%	0.46%	3.17%	3.12%	6.87%	-3.76%	-0.58%
2008	1.33%	-1.13%	2.46%	0.77%	6.33%	-5.57%	-3.11%
2009	-0.29%	0.31%	-0.60%	1.09%	5.64%	-4.55%	-5.15%
2010	-1.54%	2.62%	-4.15%	3.78%	1.92%	1.86%	-2.30%
2011	-1.41%	-0.24%	-1.17%	1.82%	2.99%	-1.17%	-2.34%
2012	-0.20%	0.59%	-0.79%	2.50%	3.40%	-0.90%	-1.69%
2013	3.04%	0.38%	2.66%	2.14%	2.96%	-0.83%	1.83%
2014	0.61%	0.49%	0.12%	2.36%	2.89%	-0.53%	-0.42%
2015	1.31%	1.13%	0.18%	2.15%	2.37%	-0.22%	-0.04%
2016	-0.75%	-0.32%	-0.43%	0.76%	1.86%	-1.10%	-1.52%
2017	-2.06%	0.52%	-2.58%	2.42%	1.58%	0.84%	-1.74%
2018	0.09%	0.99%	-0.90%	3.18%	1.68%	1.50%	0.60%
2019	-0.08%	0.72%	-0.79%	2.51%	3.45%	-0.94%	-1.73%
2020	-2.89%	-1.75%	-1.14%	-0.60%	0.37%	-0.97%	-2.11%
Average	**0.06%**	**0.34%**	**-0.28%**	**2.00%**	**3.17%**	**-1.17%**	**-1.45%**

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

A. Figure 5 provides the TFP and input price differentials and the resulting *X* factor using the Northeast electric distribution sample and its RC TFP and input price results over the 2006-2020 period.

Figure 5

***X* Factor for the Northeast Electric Distribution Sample**
2006-2020

	TFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
2006	-	-	-	-	-	-	-
2007	-0.12%	0.46%	-0.58%	3.12%	6.33%	-3.21%	-3.79%
2008	0.37%	-1.13%	1.50%	0.77%	6.41%	-5.64%	-4.14%
2009	-1.09%	0.31%	-1.40%	1.09%	5.25%	-4.16%	-5.57%
2010	-3.45%	2.62%	-6.07%	3.78%	2.17%	1.61%	-4.46%
2011	-2.77%	-0.24%	-2.53%	1.82%	2.88%	-1.05%	-3.58%
2012	-1.71%	0.59%	-2.30%	2.50%	3.45%	-0.96%	-3.25%
2013	6.10%	0.38%	5.72%	2.14%	3.25%	-1.12%	4.61%
2014	-2.05%	0.49%	-2.54%	2.36%	2.70%	-0.34%	-2.89%
2015	3.65%	1.13%	2.53%	2.15%	2.30%	-0.14%	2.38%
2016	-0.01%	-0.32%	0.31%	0.76%	1.82%	-1.06%	-0.75%
2017	1.05%	0.52%	0.53%	2.42%	1.71%	0.71%	1.24%
2018	0.40%	0.99%	-0.59%	3.18%	5.82%	-2.64%	-3.23%
2019	1.75%	0.72%	1.04%	2.51%	3.18%	-0.67%	0.37%
2020	-2.84%	-1.75%	-1.09%	-0.60%	-3.70%	3.10%	2.01%
Average	**-0.05%**	**0.34%**	**-0.39%**	**2.00%**	**3.11%**	**-1.11%**	**-1.50%**

Q. Figures 4 and 5 indicate that the *X* factor for both the National sample and the Northeast subsamples is negative. Is it unreasonable for the *X* factor to be negative?

A. No. This is consistent with the results of our previous electric and gas studies in Massachusetts. For both the National sample and Northeast subsample, industry RC TFP growth is slightly positive, but the differential between industry RC TFP growth and economy-wide productivity growth is negative. Similarly, the differential between economy-wide and industry input price growth is negative. Together, the negative productivity differential and the negative input price differential produce a negative *X* factor.

Recent decisions by the Department in electricity PBR proceedings confirm the validity of a negative *X* factor.[23]

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-reduction 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 (exogenous) to the individual firm's actual performance. For example, although target revenues are determined under a revenue cap, the firm still has the incentive to minimize its costs—i.e., the profit motive is fully operative—and this incentive is not dependent on the magnitude or sign of the *X* factor.[24] 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.

[23] D.P.U. 17-05, November 30, 2017; D.P.U. 18-150, September 30, 2019; D.P.U. 19-120, October 30, 2020.

[24] For example, suppose there is an economy-wide shock (e.g., an oil price hike) that results in a contraction of the supply curve in a competitive market, ceteris paribus. The interaction of supply and demand will cause prices in a competitive market to rise, which is the competitive market counterpart to a negative *X* factor in a regulated setting. The incentives for each individual competitive firm to minimize costs and be as efficient as possible are not altered by the fact that prices in this given period have increased rather than decreased.

Q. In your opinion, what is the appropriate value of the *X* factor for NSTAR's revenue cap?

A. Our analysis shows that the *X* factor of -1.45 for the National sample provides a balance between the economic measure of RC TFP and non-economic considerations of a traditional approach to the ratemaking process.

V. RAMIFICATIONS OF CHANGING ECONOMIC TRENDS OVER THE 10-YEAR PBR TERM

Q. In your experience, are 10-year terms common for PBR plans?

A. No, in our experience 10-year terms are not common for utility PBR plans. However, a 10-year term is feasible if the PBR plan is properly constructed to account for potential and largely unforeseen changes over the term of the plan. As described below, we believe that the Eversource PBR plan is designed to address such factors to mitigate uncontrollable risk.

Q. In the context of Eversource's proposed 10-year term for the second generation PBR plan, are there any implications for the *X* factor you are recommending in this proceeding?

A. Yes. There are several potential ramifications that changing trends in costs or electric sales could have for the *X* factor specification that we have developed on the basis of the TFP Study. For example, our model is estimated with the most recent 15 years of historical data consistent with the Department's precedent and is used for purposes of a revenue-cap type PBR adjustment. As we explained above, the proper measure of output when TFP is used in a revenue cap is customer growth, which differs from the measure of output in an efficiency measure of TFP. Alternative measures of output, such as megawatt hours ("MWh") or peak load are not typically used for a revenue cap PBR model, but would be used for a price cap model. This is a consideration because, in this proceeding, we are aware that the Company is proposing cost treatment within the PBR Plan for large-scale infrastructure projects that will be needed to assure the continued reliability of the electric system as movements to electrification start to take hold. If sales trends reverse in the future from a pattern of constant decline, which has been the experience over the 15-year historical period used for our study, to a pattern of positive year-over-year growth, the implications of positive MWh volume growth for the Eversource PBR Plan and the associated *X* factor may be that a price cap form of PBR is better designed to fit that environment and the revenue cap and decoupling of the current plan are replaced with a price cap. If this is the case, the TFP output measure in our *X* factor calculations would change to one that is based on MWh hours.

Q. Have you evaluated what the results of your *X* factor derivation would be if the customer growth measure of TFP output used in the model was changed to a MWh growth measure of TFP output?

A. Based on our discussions with Eversource, it does not appear that a reversal of the historical sales trend for the distribution business is necessarily anticipated in the next 10 years and the RDM remains in place to assist in recovering the approved revenue targets for that reason. If, during the 10-year term of the PBR Plan, the anticipated forces of electrification take hold earlier than anticipated, it would be necessary to consider what the *X* factor would look like as part of a price-cap plan designed to support utility operations on the basis of MWh sales.

Q. Have you also evaluated what the results of your *X* factor derivation would be if electric utility costs or investment trends changed over the 10-year term of the proposed PBR Plan?

A. As additional years of data become available over the next 10 years, the TFP and input price differentials, and therefore the value of the calculated *X* factor, will undoubtedly change, although the direction and magnitude of that change is indeterminate at this point in time. Over the past five years, the changes in TFP and the calculated *X* factor have not varied significantly for gas and electric utilities as the study periods have rolled forward. However, over an extended term of 10 years, we understand both the gas and electric industries are expected to see very significant change in the operating environment, which could affect both inputs and outputs in relation to total factor productivity. For example, reliance on electric power supply continues to grow, spurring electric utility investment in infrastructure renewal and development. Whether and how the interaction of increased investment and a reversal in sales patterns manifests in the total factor productivity analysis will be a dynamic worth monitoring.

Q. In your opinion, are the components of the PBR Plan that Eversource is proposing important to maintain the integrity of the PBR Plan incentives over an extended 10-year term?

A. Yes. The proposed Eversource PBR Plan includes several elements to address unforeseen events and to mitigate uncontrollable risk. These components include a Z factor (exogenous cost factor), capital cost factor (discussed by Company Witness Dr. Kaufmann) and an earning sharing mechanism. These components are reasonable concepts to adopt as part of the long-term PBR Plan to maintain the balance of customer benefits and economic incentives that are critical to the effective operation of the PBR Plan.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX: TOTAL FACTOR PRODUCTIVITY STUDY

Overview

This study of total factor productivity ("TFP") is specifically designed to be used in developing the *X* factor for a revenue cap. *Revenue cap TFP* ("RC TFP") growth is specified as:

$$\text{RC TFP Growth} = \%\Delta\, TFP^{R}_{I} = \%\Delta CUSTOMERS_{I} - \%\Delta Total\ Input_{I}$$

Where $\%\Delta CUSTOMERS_I$ represents the measure of industry output for RC 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 NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, D.P.U. 17-05 (2017), as well as Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, D.P.U. 18-150 (2019), for the estimation of electric distribution industry TFP subject to certain refinements designed to capture additional costs typically considered in traditional ratemaking contexts. Specifically, the model incorporates customer accounts and sales expenses, as well as a portion of administrative and general ("A&G") expenses in the computation of Total Input. Customer accounts and sales expenses are incorporated into the model by including labor and materials expense for relevant FERC Form 1 accounts, as these accounts can be credibly attributed to the distribution function of the utilities.

A&G accounts are a different matter. A&G accounts reflect the costs of activities that span the functional components of the utility—e.g., distribution, transmission and generation. Therefore, the assignment of a portion of these expenses to the distribution function requires that these A&G

expenses be apportioned to the utilities' functional components in a non-causal manner. Because there is not a causal relationship between the joint and common A&G expenses and the functional components of the utility, there is no economically unique or acknowledged method to assign these expenses to the distribution functions.

A listing of firms in the sample is provided in Figure A.3. FERC Form 1 sources for data used in the model is found in Figure A.4.

Output

Because the results of the study are to be applied to a revenue cap, it is appropriate to base the output measure on the number of customers served. The revenue cap being proposed by the Company is more comparable to a revenue per customer cap than a price cap. 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). In a revenue per customer cap, revenues are allowed to increase by the percentage increase in the inflation factor, plus or minus the *X* factor, plus the increase in the number of customers. For a revenue cap, such as that proposed by the Company, this relationship also holds but revenues are not allowed to increase with the percentage increase in the number of customers. In this respect, the percentage change in customers is an implicit stretch factor in the revenue cap formula.

To see that customer growth is the appropriate output measure for revenue per customer and revenue caps, assume the I factor is given by a measure of industry input inflation, and, first, decompose total revenue growth into revenue per customer ("*RPC*") and customer growth:

$$\%\Delta R_I = \%\Delta RPC_I + \%\Delta CUSTOMERS_i$$

Rearranging:

$$\%\Delta RPC_I = \%\Delta R_I - \%\Delta CUSTOMERS_i$$

Under competitive conditions, the growth in the total revenue of the industry ($\%\Delta R_I$) is equal to the growth in its cost ($\%\Delta C_I$)—i.e., $\%\Delta R_I = \%\Delta C_I$. The rate of cost change can be decomposed into the rate of input price change ($\%\Delta W_I$) plus the rate of input quantity change ($\%\Delta Q_I$)—i.e., $\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I$. Substituting $\%\Delta C_I$ for $\%\Delta R_I$ in yields:

$$\%\Delta RPC_I = \%\Delta C_I - \%\Delta CUSTOMERS_i$$

Substituting %ΔWI + %ΔQI for %ΔCI:

$$\%\Delta RPC_I = \%\Delta W_I + \%\Delta Q_I - \%\Delta CUSTOMERS_i$$

Rearranging:

$$\%\Delta RPC_I = \%\Delta W_I - (\%\Delta CUSTOMERS_i - \%\Delta Q_I)$$

$$\%\Delta RPC_I = \%\Delta W_I - \%\Delta TFP'_I$$

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. This represents a revenue per customer cap formula where the I factor is industry input price growth (i.e., $\%\Delta W_I$). This is the same formula for a revenue cap where $\%\Delta RPC_I$ is replaced with $\%\Delta R_I$. However, an important difference between a revenue per customer cap and a revenue cap is that a revenue cap does not typically allow revenue to change with customer growth.

The data source for the output measure is "Sales to Ultimate Customers" found in the EIA 861 reports. The file used in "Sales_Utl_Cust_XXXX.xlsx", where XXXX signifies the year. Bundled and Delivery customers are included.

Distribution Labor

To measure distribution labor input, we base labor cost on the direct payroll distribution booked to electricity distribution operating and maintenance expenses found in the FERC Form 1 (see Figure A.4). The price of labor is based on the Bureau of Labor Statistics Employment Cost Index for utility industry wages and salaries,[25] 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 FERC Form 1 less direct payroll distribution described above (see Figure A.4). The price of materials is based on the Bureau of Economic Analysis Gross Domestic

25 Bureau of Labor Statistics, Wages and Salaries for Private Industry Workers in Utilities, 12-month percent change, Series ID CIU2024400000000A (http://www.bls.gov/ncs/ect/)

Product Price Index, while the quantity of materials is derived by dividing the cost of materials by its price.

Customer Accounts and Sales Labor and Materials

The following FERC Form 1 accounts are used to determine customer accounts and sales expenses that are included in O&M expenses:

Customer Accounts Expenses
(901) Supervision
(902) Meter Reading Expenses
(903) Customer Records and Collection Expenses
(905) Miscellaneous Customer Accounts Expenses
Sales Expenses
(911) Supervision
(912) Demonstrating and Selling Expenses
(913) Advertising Expenses
(916) Miscellaneous Sales Expenses

The labor expense portion of customer accounts and sales expenses are line items in the FERC Form 1 (see Figure A.4). The price of labor is based on the Bureau of Labor Statistics Employment Cost Index for utility industry wages and salaries,[26] with the quantity index of labor derived by dividing the cost of labor by its price.

Materials expenses for customer accounts and sales expenses are determined by the total O&M expenses for these accounts less the direct payroll distribution for these accounts (see Figure A.4).

[26] Bureau of Labor Statistics, Wages and salaries for Private industry workers in Utilities, 12-month percent change, Series ID CIU2024400000000A (http://www.bls.gov/ncs/ect/)

The price of materials is based on the Bureau of Economic Analysis Gross Domestic Product Price Index, while the quantity of materials is derived by dividing the cost of materials by its price.

Administrative and General Labor and Materials

Administrative and General ("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. Capturing any additional distribution-related costs that may be contained in these accounts comes at the expense of relying on additional and uncertain assumptions, and there is simply no economically unique approach to determining distribution-related costs from the joint and common A&G expense accounts. Economic literature recognizes that there is not a unique, economically causal method to allocate joint and common costs.[27] Allocations of joint and common costs are arbitrary from an economic

[27] For example, in the context of calculating a rate of return, Baumol, Koehn, and Willig illustrated the economic arbitrariness of joint and common cost allocations by allocating hypothetical railroad investment among three different commodities—lead, balsa wood, and precious metals—using three different, presumably reasonable, allocation methods—carloads, weight and value. The resulting investment allocations were wildly different depending on the method of allocation. The authors concluded that:

> Fully allocated cost figures and the corresponding rate of return numbers simply have zero economic content. They cannot pretend to constitute approximations to *anything*. The "reasonableness" of the basis of allocation selected makes absolutely no difference except to the success of the advocates of the figures in deluding others (and perhaps themselves) about the defensibility of the numbers. There just can be no excuse for continued use of such an essentially random or, rather, fully manipulable calculation process as a basis for vital economic decisions by regulators.
>
> William J. Baumol, Michael F. Koehn, and Robert D. Willig, "How Arbitrary is 'Arbitrary'?—or, Toward the Deserved Demise of Full Cost Allocation," *Public Utilities Fortnightly* Volume 120, Number 5, September 3, 1987, at 21 (emphasis in original).

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perspective because it cannot be determined what portion of a joint and common input designed to provide multiple products or services is properly ascribed to a single product or service. Accordingly, judgment is involved in any allocation of joint and common costs.

Conversely, from a regulatory perspective, a utility's distribution function is responsible for covering some portion of A&G costs. Therefore, this TFP study adopts a regulatory, non-economic apportionment principle for assigning A&G expenses to distribution. Specifically, the portion of joint and common A&G expenses allocated to the distribution function is determined by multiplying a firm's total A&G expenses for each year in the sample by the annual average across all firms in the sample of the percent of distribution plant relative to total plant.

The following A&G expense categories were included in the model:

Administrative and General Expenses
(920) Administrative and General Salaries
(921) Office Supplies and Expenses
(922) Administrative Expenses Transferred - Credit
(923) Outside Services Employed
(924) Property Insurance
(925) Injuries and Damages
(926) Employee Pensions and Benefits
(928) Regulatory Commission Expenses
(930.1) General Advertising Expenses
(930.2) Miscellaneous General Expenses
(931) Rents

The labor expense portion of A&G expenses are line items in the FERC Form 1 (see Figure A.4). The price of labor is based on the Bureau of Labor Statistics Employment Cost Index for utility industry wages and salaries,[28] with the quantity index of labor derived by dividing the cost of labor by its price.

Materials expenses for A&G expenses are determined by the total expenses for these accounts less the direct payroll distribution for these accounts (see Figure A.4). The price of materials is based on the Bureau of Economic Analysis Gross Domestic Product Price Index, while the quantity of materials is derived by dividing the cost of materials by its price.

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 under the hyperbolic model of capital decay. The perpetual inventory equation constructs an end-of-year capital stock from the capital stock at the end of the previous year and the quantity of capital stock additions during the year, using a hyperbolic decay function to address efficiency losses over time. The hyperbolic model relies upon two fundamental assumptions. First, the model assumes that distribution plant-in-service consists of a collection of assets with differing service lives, represented by a truncated normal distribution with a mean equal to the average service life (L) of

[28] Bureau of Labor Statistics, Wages and salaries for Private industry workers in Utilities, 12-month percent change, Series ID CIU2024400000000A (http://www.bls.gov/ncs/ect/)

all assets together and a standard deviation of L/4. While some components of plant in service may reach retirement prior to 33 years and other components may reach retirement after 33 years, *on average* plant will retire at the peak of the bell curve, the average service life.

The hyperbolic model's second assumption is that, individually, electric distribution assets provide a slowly declining level of service (i.e., capital input) during the initial period of the asset's lifetime, followed by a more rapid efficiency decay in the later period of the asset's lifetime. The trend of efficiency decay is defined by the hyperbolic function has the following form, where assets that are retired at age N:

$$S_t = \frac{N - t}{N - \beta t}, t < N$$

Where S_t is the relative efficiency of an asset in year t and β serves as a parameter effecting rate of decay. For β, the BLS uses a parametric value of 0.75 for structures.[29] In our distribution capital input calculations, we use this same parameter.

The construction of capital stock under the hyperbolic model combines the two assumptions described above. The hyperbolic model assumes that individual assets will decay slowly at first, then more quickly as they approach retirement, and that these individual asset retirement ages follow a truncated normal distribution. When these assumptions are combined, the decay of distribution plan efficiency *on average* follows a backwards "S" shape. The cohort average

29 Note that choosing a value for β equal to 1.0 would result in asset decay equivalent to OHS, where asset efficiency does not decay over the life of the asset. In this way, the OHS approach is a subset of the more generalized hyperbolic model.

efficiency decay trend reflects the hyperbolic model assumption that some plant efficiency exists beyond the average service life, since some subset of plant in fact retires after the class average retirement.

Our study period begins in 2006. To estimate capital input for the year 2006, we need an end of year capital stock estimate for 2005. That in turn requires projections of investment back to 1940, since the hyperbolic model assumes asset retirements of a normal distribution of 65 years. Since existing data dates back to 1964, capital investment was estimated for the years prior. Because the net book value of distribution plant is not reported in the FERC Form 1, it is estimated by taking the ratio of distribution plant in service to total electric plant in service[30], and applying it to net electric plant in service.[31] Using the variable HW to represent the Handy-Whitman index, the mathematical formula to construct the benchmark value is as follows.

$$K_{1964} = \frac{NetElectricPlantInService \cdot \left({}^{DistributionPlantInService}/_{TotalPlantInService} \right)}{\sum_{i=1}^{20} \left[{}^{i \cdot HW_{1944+i}}/_{\left(\sum_{i=1}^{20} i\right)} \right]}$$

Using this assumption and the average age and efficiency parameters described above, we can project the relative efficiency of the benchmark capital stock for the years 2006 through 2020.

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[30] Distribution plant in service is found in the FERC Form 1, page 205, line 75, column g. Total plant in service includes production plant in service (page 205, line 46, column g), transmission plant in service (page 205, line 58, column g), general plant in service (page 205, line 99, column g), and distribution plant in service.

[31] FERC Form 1, page 200, line 15, column c.

Once the end-of-year capital stock is computed, the flow of capital services during a year is based on the quantity of capital stock at the end of the previous year, after accounting for the hyperbolic decay of capital inputs. To estimate the quantity of additions during the year, we divide distribution additions to plant in service by the Handy-Whitman index for distribution plant

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 under hyperbolic decay has the following mathematical representation.

$$p_t = \frac{(1-uz)}{(1-u)} \cdot \left[\sum_{i=1}^{65} \left(\frac{1+\rho}{1+r} \right)^i \delta_i \right]^{-1} HW_{t-1}$$

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 65 is twice the average service life, minus one, which is the range of asset lifetimes under the truncated normal distribution.

Based on tax law, we use a corporate tax rate of 35% for u during the years before the Tax Cuts and Jobs Act, and 21% for subsequent years. 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.[32] We apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2006-2020 period. The average cost of capital is based on the Moody's seasoned AAA bond yield, published by the Federal Reserve Bank of St. Louis.[33] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[34]

Total Input

We construct the quantity index of total input for each firm and each year by using the

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32 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.

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

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

multilateral Tornqvist indexing procedure.[35] The multilateral Tornqvist index has the form:

$$ln(X_{i,t}) = .5 \cdot \sum_{j=1}^{7} (sy_{jit} + \overline{sy_J}) \cdot (lnX_{jit} - \overline{lnX_J})$$

Where

i = firm (i = 1 … 65)

t = period (t = 2006 … 2020)

j = input (j = 1 … 7)[36]

$X_{i,t}$ = 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:

$$ln(P_{i,t}) = .5 \cdot \sum_{j=1}^{7} (sy_{jit} + \overline{sy_J}) \cdot (lnP_{jit} - \overline{lnP_J})$$

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35 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.

36 As described above, the inputs are distribution labor, distribution materials, customer accounts and sales labor, customer accounts and sales materials, A&G labor, A&G materials, and capital.

Where

i = firm (i = 1 … 65)

t = period (t = 2006 … 2020)

j = input (j = 1 … 7)[37]

$P_{i,t}$ = 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.

Industry 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 the 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:

[37] As described above, the inputs are distribution labor, distribution materials, customer accounts and sales labor, customer accounts and sales materials, A&G labor, A&G materials, and capital.

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

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 RC 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:

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

Figure A.1 provides average growth of input components for plant-apportioned A&G models for the National Sample, and Figure A.2 provides average growth of input components for plant-apportioned A&G models for the Northeast sample.

<u>Sample</u>

The national sample consists of 65 firms, compared to 67 in the previous Eversource study. Two firms were deleted; one firm was acquired; and, one firm was added to the Eversource sample. One of the firms in the Eversource study, Entergy, Gulf States, LA LLC, merged with Entergy Louisiana in 2015 and, therefore, is no longer an independent entity. Another firm from the Eversource study, Entergy Mississippi, Inc., was dropped after it was discovered that the data confused this company with Mississippi Power from 1964 to 1999. Consolidated Edison Company of New York was added to the sample as an error in the company's data was able to be rectified. In 2017, Western Massachusetts Electric Company was acquired by Eversource, and no longer reports a separate FERC Form 1. Figure A.3 shows the companies included in the study and Figure A.4 shows the FERC Form 1 data sources used in the study.

Figure A.3
Firms in Sample

Alabama Power Company
Appalachian Power Company
Arizona Public Service Company
Baltimore Gas and Electric Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corp*
Cleveland Electric Illuminating Company
Commonwealth Edison Company
Connecticut Light and Power Company*
Consolidated Edison Company of New York, Inc.*
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
Detroit Edison Company
Duke Energy Indiana, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company*
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Florida Power Corporation
Green Mountain Power Corporation*
Gulf Power Company
Idaho Power Company
Indiana Michigan Power Company
Jersey Central Power & Light Company*
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Utilities Company
Madison Gas and Electric Company
Massachusetts Electric Company*
MDU Resources Group, Inc.
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company*
Narragansett Electric Company*
Nevada Power Company
New York State Electric & Gas Corp*
Niagara Mohawk Power Corporation*
Northern Indiana Public Service Co.
NSTAR*
Ohio Edison Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.*
Otter Tail Corporation
Pacific Gas and Electric Company
PECO Energy Company*
Pennsylvania Electric Company*
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Hampshire*
Public Service Electric and Gas Company*
Puget Sound Power and Light Company
South Carolina Electric & Gas Co.
Southern California Edison Co.
Southern Indiana Gas and Electric Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Tucson Electric Power Company
Virginia Electric and Power Company
Wisconsin Electric Power Company
Wisconsin Public Service Corp

*Northeast Sample

Figure A.4
FERC Form 1 Data Sources

Page 354, FERC Form 1: "Distribution of Wages and Salaries"

	Line Number
Distribution	23
Customer Accounts	24
Sales	26
Administrative and General	27

Pages 320-323, FERC Form 1: "Electric Operation and Maintenance Expenses"

	Line Number
Total Power Production Expenses	80
Total Transmission Expenses	112
Total Distribution Expenses	156
Uncollectible Accounts	162
Total Customer Account Expenses	164
Franchise Requirements	188
Maintenance of General Plant	196
Total Administrative and General Expenses	197
Total Electric Operations and Maintenance Expenses	198

Pages 204-207, FERC Form 1: "Electric Plant in Service"

	Line Number	Line Change
Total Production Plant	42	Through 2002
Total Production Plant	46	After 2002
Total Transmission Plant	53	Through 2002
Total Transmission Plant	58	After 2002
Total Distribution Plant*	69	Through 2002
Total Distribution Plant*	75	After 2002
Total General Plant	83	Through 2002
Total General Plant	90	2003
Total General Plant	99	After 2003
Total Electric Plant in Service	88	Through 2002
Total Electric Plant in Service	95	2003
Total Electric Plant in Service	104	After 2003

*Columns C and D for Additions and Retirements, respectively

<u>TFP and Input Price for the U.S. Economy</u>

The Gross Domestic Product Price Index (GDPPI)[38] is a comprehensive measure of output prices in the U.S. economy. Changes in the GDPPI 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 GDPPI is related to percentage changes in economy-wide input prices and total factor productivity in the following way.

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

The broadest measure of total factor productivity for the U.S. economy is the BLS multifactor productivity index for the private business sector.[39] We use the private business sector multifactor productivity index as a proxy measure of total factor productivity 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 total factor productivity for the U.S. economy, we can simply calculate the percentage change in U.S. economy input prices for any given year by

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[38] 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)

[39] 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/)

adding the percentage change in GDPPI and the percentage change in U.S. economy total factor productivity.

Supporting Documentation

There are two workbooks that show the computations underlying the results for the nationwide sample and the Northeast subsample. Results for the nationwide subsample are found in the workbook "National Model," while the results for the Northeast subsample are found in the workbook "Northeast Model." Both workbooks have the same structure. 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 Gross Domestic Product Price Index, the worksheet "ECI" shows the downloaded Employment Cost Index, and the worksheet "HW Data" shows the downloaded Handy-Whitman Indexes.

The worksheet "Capital Stock" 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 R show the computation of the price, quantity, and value of labor input, specifically for Customer Accounts and Sales. Columns T through X show the computation of the price, quantity, and value of materials input, specifically for Customer Accounts and Sales. Columns Z through AC show the computation of the price, quantity, and value of labor input, specifically for Administrative and General expenses allocated by Plant. Columns AE through AI show the computation of the price, quantity, and value of material input, specifically for Administrative and General expenses allocated by Plant. Columns AK through AS show the computation of the price, quantity, and value of materials input. Columns AU through BF show the computation of the price, quantity, and value of capital input. Columns BH through DN show the computation of the quantity of total input that results from the application of the multilateral Tornqvist index formula. Lastly, the worksheet "Results" shows the final results for the nationwide sample and the Northeast subsample.