Determination of the Third-Generation X Factor for the AUC Price Cap Plan

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Christensen Associates Energy Consulting
January 20, 2023

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1. Introduction

1. We are Dr. Mark E. Meitzen and Mr. Nicholas A. Crowley. We are employed by Christensen Associates Energy Consulting ("CAEC"), a wholly-owned subsidiary of Christensen Associates. Our business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin. We have been retained by EPCOR Distribution & Transmission Inc. ("EDTI") in this proceeding to provide our expert evidence respecting issues 4 and 6 on the Alberta Utilities Commission ("AUC") final issues list regarding the third-generation PBR framework ("PBR3").[1] In particular, we calculate electric distribution industry total factor productivity for the purpose of establishing an *X* factor for EDTI (Issue 4). Regarding Issue 6, we survey the use of earnings sharing mechanisms ("ESMs") in various jurisdictions, provide evidentiary support for EDTI's *X* factor premium proposal and analyze the relationship between three benefit sharing mechanisms ("BSMs") and associated *X* factor premium values. We acknowledge that we have a duty to provide opinion evidence to the Commission that is fair, objective and non-partisan. The documents we have relied on in forming our expert opinion can be found in the footnotes of this evidence. The workpapers supporting our empirical analysis have been filed with this evidence.

1.1. Qualifications

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

[1] Alberta Utilities Commission, "Third Generation Performance-Based Regulation (PBR3), Proceeding 27388: Ruling on Final List of Issues," September 16, 2022.

3. Dr. Meitzen has co-authored a number of other productivity studies conducted by Christensen Associates, including a study prepared on behalf of EDTI for its second-generation PBR plan, and a number of other studies for electric and gas distribution companies. He has also performed a number of studies for the telecommunications industry, including a productivity analysis on behalf of AT&T and 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. He has analyzed incentive regulation issues for various network industries including the telecommunications, electric and gas utilities and postal industries. He also directed the Christensen Associates team that analyzed incentive-regulation options for the privatization of Peru's telecommunications industry.

4. Among the articles and reports that he has written, he recently co-authored three articles on PBR in the electric utility industry (including one with Mr. Crowley).[2] He has 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. Dr. Meitzen's curriculum vitae is provided in Appendix B.

5. Mr. Crowley is a Senior Economist with Christensen Associates. He has a Bachelor of Science in economics, as well as a Master of Science in economics from the University of Wisconsin-Madison. He began working at Christensen Associates in 2016. He has recently testified with Dr. Meitzen on behalf of NSTAR Electric Company in D.P.U. 22-22 and Boston Gas Company and the former Colonial Gas Company each d/b/a National Grid in D.P.U. 20-120 in Massachusetts.[3] He has also calculated total factor productivity measures for the electricity sector and developed indexes for use in performance-based ratemaking in proceedings before the Department of Public

[2] 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.

[3] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, January 14, 2022; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, June 10, 2022. 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.

Utilities on behalf of Massachusetts Electric in D.P.U. 18-150[4] and on behalf of NSTAR Electric in D.P.U. 17-05.[5] Prior to joining Christensen Associates, he was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission ("FERC"), where he assisted with energy industry benchmarking, the incentive regulation of oil pipelines under Docket RM15-20,[6] and the review and evaluation of natural gas pipeline rate cases. In these roles, he has worked extensively with FERC data, and other federal data, vis-à-vis the development of cost benchmarks for power systems and in marginal cost models filed before regulatory authorities in the United States and Canada. He has recently co-authored an article with Dr. Meitzen on the impact of price-cap regulation on Canadian electricity distribution utilities.[7] Mr. Crowley's curriculum vitae can is provide in Appendix B.

1.2. Outline of Evidence

6. The AUC has set forth a number of issues on which it seeks input regarding the third-generation PBR framework. Issue 4 in the AUC's final list of issues in this proceeding is: what is the appropriate value of the *X* factor for ("PBR3") term?[8] Under that question, the Commission asks for an "Industry total factor productivity calculation" and "The magnitude of the stretch factor in PBR3 plans." Responsive to issue 4, we have conducted a TFP study for EDTI to determine the industry total factor productivity growth for the third-generation price cap PBR plan. Issue 6 of the AUC's final list of issues in this proceeding considers whether an earnings sharing mechanism ("ESM") or other mechanism should be implemented for PBR3 to ensure that the benefits of PBR are sufficiently shared with utility customers.[9] Responsive to

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[4] 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.

[5] 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.

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

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

[8] Alberta Utilities Commission, "Third Generation Performance-Based Regulation (PBR3), Proceeding 27388: Ruling on Final List of Issues," September 16, 2022.

[9] Alberta Utilities Commission, "Third Generation Performance-Based Regulation (PBR3), Proceeding 27388: Ruling on Final List of Issues," September 16, 2022.

issue 6, we provide an analysis of the use of ESM's in other jurisdictions' PBR plans. We then provide an analysis of three BSM options and appropriate premiums on the *X* factor for benefits sharing purposes: (1) a standard ESM, (2) an *X* factor premium, and (3) a high-powered ESM.

2. Overview of Key Results

7. Using an industry sample of 65 firms, we compute total factor productivity growth for the third-generation AUC PBR plan for EDTI, an electric distribution utility in Alberta. Our sample consists of the most recent 15-year period, 2007-2021, which strikes a reasonable 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.

8. In the AUC $I - X$ price cap formula, I is a measure of industry input inflation. In this specification, *X* is determined by industry total factor productivity ("TFP") growth. The computation of TFP growth for use in the price cap formula typically uses MWh growth as its measure of output. The results of our TFP study produces TFP growth or an *X* factor of -1.08 percent. Note that the *X* factor is negative, meaning that the cap allows rates to increase faster than the input inflation rate. This does not necessarily imply that the industry has been less productive over time, since the price cap TFP measure is not a measure of pure industry efficiency. Instead, a price cap TFP measure reflects the relationship between industry-wide growth in input costs and industry-wide growth in only the outputs associated with prices on a customer's bill.

9. Regarding Issue 6, EDTI has proposed that an *X* factor premium of 0.30 percent, which is 1.5 times the stretch factor in the first-generation AUC PBR plan and almost six times the implied stretch factor of the second-generation AUC PBR plan. The 0.30 percent *X* factor premium, is within the range of industry stretch factors, and when added to the computed *X* factor provides a reasonable amount of incremental benefit to EDTI's customers. Given the computed *X* factor is -1.08 percent (to be paired with a standard ESM), the composite *X* factor (i.e., computed *X* factor + *X* factor premium) would be -0.78 percent (-1.08 + 0.30) under the *X* factor premium approach. Alternatively, using the high-powered ESM developed by Dr. Weisman, an appropriate associated X factor premium would be 0.24 percent, resulting in a composite *X* factor of -0.84 percent.

3. Overview of the AUC Price Cap Plan for EDTI

3.1. AUC Price Cap Formula

10. The cornerstone of the AUC PBR plan is based on what is referred to as price cap regulation. A pure price cap formula has the general form of "$I - X$," where I is a measure of input inflation and X is a measure of productivity growth. Under price cap regulation, the rates that can be charged by the regulated company are governed by a formula that effectively limits changes in rates to some measure of inflation, adjusted for the industry's ability to offset inflation with gains in productivity, i.e., the $I - X$ formula sets a ceiling on price changes for services that are subject to the price cap. The price cap approach to regulation is based on the proposition that in competitive markets the prices charged for a product or service are determined by the prices of the inputs used to produce the product or service, adjusted for any productivity gains exhibited in combining those inputs to produce the product or service.[10]

11. The price cap formula adopted in PBR1 and PBR2 by the AUC augments the "pure" $I - X$ price cap formula with additional factors and has the form:

$$(1)\ \%\Delta P = (I - X) +/- Y +/- Z +/- K^1 +/- K^2$$

Where

$\%\Delta P$ = allowed change in capped price
I = inflation factor
X = productivity factor
Y = recurring flow through items, collected through Y factor rate adjustments
Z = one-time exogenous adjustments
K^1 = Type 1 capital recovered through capital trackers
K^2 = Type 2 capital recovered through K-bar in the second-generation AUC PBR plan

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[10] 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 plans in Massachusetts and Hawaii), then, 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*.* Also, X and the underlying measure of industry TFP depends on whether TFP is being used to calibrate a price cap or a revenue per customer cap.

The *X* factor in the AUC price cap plan is discussed at greater length below. Regarding the other adjustment factors in the plan, the *I* factor in the AUC price cap plan represents the changes in industry input prices over the term of the PBR plan, consisting of a weighted average of labor costs and non-labor input costs.[11] *Y* and *Z* factors provide flexibility for the regulator and the regulated firm to address cost increases that are outside of management's control. *K* factors provide sources of revenue in addition to that generated by the *I* – *X* mechanism to sufficiently accommodate capital spending.

3.2. TFP is the Basis of the X Factor in the AUC Price Cap Formula

12. The productivity concept used in the AUC price cap formula is total factor productivity ("TFP"), which is defined as the ratio of total output to total input:

$$(2)\ TFP = \frac{Total\ Output}{Total\ Input}$$

13. Thus, industry productivity gains 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:[12]

$$(3)\ \%\Delta TFP = \%\Delta Total\ Output - \%\Delta Total\ Input$$

14. Total output consists of all the services produced by the relevant unit of production (e.g., a firm or an industry). Total input includes all resources used by the unit of production in providing those services. Typically, TFP studies have three components

[11] Labor costs are represented by Alberta average weekly earnings (AWE) for the previous July through June period and other input costs are represented by the Alberta consumer price index (CPI) for the previous July through June period. Under the current PBR framework, weights for the I factor are 55 percent for AWE and 45 percent for CPI. See AUC Decision 2012-237, p. 52. The 2016 AUC decision for the second-generation PBR plan left this unchanged. See AUC Decision 20414-D01-2016, p.2 and pp. 88-89.

[12] Given that the *I* factor in the AUC price cap plan measures input price inflation as opposed to output price inflation, the *X* factor is based on industry TFP growth. If, on the other hand, the *I* factor would have been based on a measure of output inflation (as is common in most U.S. PBR plans), the *X* factor would have to make adjustments for differences in productivity and input price growth between the industry and the overall economy. See AUC Decision 2012-237, pp. 87-89. As summarized on p. 89 of the Decision:

> [S]ince both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.

of total input: capital, labor, and materials. 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.

15. The AUC determined the electric distribution PBR plan should incorporate an *X* factor set according to industry expected productivity growth.[13] Such a forward-looking productivity growth trend may be estimated using historical data. This calculation involves determining the appropriate time frame of the historical measurement of TFP that translates into forward-looking productivity and the appropriate industry grouping that best represents the Alberta electric distribution industry. As discussed below, we believe the latest available 15 years of data provides the appropriate time frame. In addition, a broad sample of U.S. distribution utilities reasonably approximates the productivity trend in Alberta.[14]

3.3. The Computation of TFP for the Purpose of Price Cap Calibration

16. The correct specification of output for a TFP 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. When the purpose of TFP measurement is for use in calibrating the *X* factor for a price cap (i.e., "PC TFP"), the output measure should reflect the elements of output associated with customer prices—i.e., billed output—because those are the elements of output whose prices are being constrained by the cap.[15] In general, these are not the same elements of the output that would be used in an efficiency measure of TFP since the billed output measure would include only those aspects of output produced by the firm or industry that are explicitly related to customer prices or revenue generation subject to the cap. In most

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[13] AUC Decision 2012-237, pp. 52-53. The use of *industry* expected productivity in setting the *X* factor provides incentives for productivity gains by the regulated firm. In contrast, if the *X* factor were to be based on actual changes in the regulated firm's own productivity, price cap regulation would function similar 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, p. 9.

[14] The AUC evaluated the relevance of a sample of U.S. utilities in setting TFP for an Alberta price cap in its first generation PBR decision, accepting such a sample because of its public availability and methodological transparency (see AUC Decision 2012-237, p. 86).

[15] For example, see Laurits R. Christensen, Philip E. Schoech, and Mark E. Meitzen, "Total Factor Productivity in the Telecommunications Industry," in *International Handbook on Telecommunications Economics*, G. Madden and S. Savage, eds., 2003.

cases, billed output would be a proper subset of the total output produced. For example, as described in a recent article co-authored by Dr. Meitzen and Dr. Weisman in *The Electricity Journal*:

> [P]roviding security in today's environment means protecting against cyber threats and drone attacks. This contrasts sharply with yesteryear's security that may have required only a night watchman and a chain-link fence. Distributed generation requires costly infrastructure investments to allow wind/solar generators to interconnect with the distribution system. Similarly, other "grid mod" investments for which there are no explicit charges to consumers, such as vehicle charging investments, contribute to the imbalance between input and output growth. All these activities require more intensive use of inputs without generating any corresponding increase in billable outputs for the electric distribution companies.[16]

17. There are two primary differences between an efficiency measure and PC TFP. First, as noted, the efficiency measure of TFP would likely contain a more comprehensive set of the outputs produced by the firm or industry. Second, the weighting of the various elements of output into a total output index differ between an efficiency measure of TFP and PC TFP used in a price cap.[17] Only in cases where all elements of output are billed to customers, and price equals marginal cost for all elements of output, will the total output measure be the same for the efficiency and price cap measures of TFP. This is typically not the case for the electric distribution industry.[18]

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[16] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018), at 43. To the extent elements of investment are not associated with billed output, their costs must be recovered from the elements of billed output.

[17] The efficiency measure of TFP uses marginal cost weights and PC TFP uses revenue weights to combine individual measures of output into an index of total output (or billed output).

[18] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018), at 43.

3.4. The Relationship Between the Specification of the *I* Factor and the *X* Factor

18. When the *I* factor is a measure of industry input inflation, as in the AUC price cap plan, the *X* factor is represented by the change in industry TFP.[19] Under competitive conditions, which economic regulation seeks to emulate, the rates of change in the revenue of the industry ($\%\Delta R_I$) are equal to the rates of change in its cost ($\%\Delta C_I$):

$$(4)\ \%\Delta R_I = \%\Delta C_I$$

19. Because revenue equals output price times billed output quantity, the rate of revenue change can be decomposed into the rate of output price change ($\%\Delta P_I$) plus the rate of billed output quantity change ($\%\Delta B_I$):

$$(5)\ \%\Delta R_I = \%\Delta P_I + \%\Delta B_I$$

20. Similarly, because cost equals input price times input quantity, 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 ($\%\Delta Q_I$):

$$(6)\ \%\Delta C_I = \%\Delta W_I + \%\Delta Q_I$$

Combining equations (4) through (6) implies that, under competitive conditions, output prices will change at a rate equal to input price inflation minus the rate of change in PC TFP (defined as the percent change in the quantity of billed output less the percent change in the quantity of total input, i.e., $\%\Delta TFP^P{}_I = \%\Delta B_I - \%\Delta Q_I$):[20]

$$(7)\ \%\Delta P_I = \%\Delta W_I - (\%\Delta B_I - \%\Delta Q_I) = \%\Delta W_I - \%\Delta TFP^P{}_I$$

where $\%\Delta TFP^P{}_I$ represents the rate of industry PC TFP change. Equation (7) is simply the "*I* – *X*" cap formula where $I_I = \%\Delta W_I$ and $X(I_I) = \%\Delta TFP^P{}_I$.

[19] Alternatively, if the *I* factor is represented by some measure of economy-wide output inflation, such as the Gross Domestic Product Price Index ("GDP-PI") in most U.S. indexed PBR plans, the *X* factor is determined by the differential in industry versus economy-wide TFP growth plus the differential in economy-wide versus industry in input price growth. See Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018), at 33-34.

[20] Intuitively, the firm's prices should be allowed to increase at the rate of industry input price inflation less the industry's increased productivity in using those inputs. A firm that is more proficient than the industry in securing lower priced inputs and is more proficient than the industry in securing productivity gains will be able to increase prices at a faster rate than the increase in its actual costs. This difference is a reward for the relatively efficient firm when it is positive and a penalty for the relatively inefficient firm when it is negative.

4. Determination of the X Factor for EDTI for the AUC Third-Generation PBR Plan

21. The *X* factor in the first- and second-generation AUC PBR plans consisted of expected industry productivity growth and a stretch factor.[21] In this section, we first describe our methodology for computing TFP. We then present the results of our TFP study.

4.1. TFP Methodology

22. The basic methodology of the TFP study presented here is consistent with the model Dr. Meitzen presented for the second-generation Alberta PBR plan.[22] However, we have made two refinements to the model since the second-generation Alberta PBR 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 ensure 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.

23. The goal of our TFP study is to develop the relevant cost trends for electric distribution utilities. From a methodological perspective, this means that all costs that

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[21] Regarding productivity, the Commission stated a clear preference for expected industry productivity growth as the basis of the X factor. This is consistent with standard, accepted practice. For example:

[T]he objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company. [See AUC Decision 2012-237, p. 60.]

In general terms, the X factor can be viewed as the expected annual productivity growth during the PBR term. [See AUC Decision 2012-237, pp. 52-53.]

The Commission also expressed that productivity studies used to establish X (including the NERA study it commissioned) should be based on publicly available data and use a transparent methodology:

> In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.
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> … [T]he significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated [sic]. [See AUC Decision 2012-237, pp. 72-73.]

[22] Mark E. Meitzen, "Determination of the Second-Generation X Factor for the AUC Price Cap Plan for Alberta Electric Distribution Companies," March 21, 2016.

are related to the distribution function should be incorporated into the model. Since the second-generation Alberta PBR proceeding, the methodology for conducting our TFP study has been updated to include customer accounts and sales expenses as distribution-related costs in order to more accurately reflect distribution utility 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 be unambiguously attributed to the distribution function of the utilities.

24. For the same methodological reason (i.e., incorporating relevant distribution-related costs in the model), we have incorporated Administrative & General ("A&G") costs into the model, although due to data filing standards 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 some electric utilities in the study group include costs associated with owning and operating distribution, transmission and generation assets, which means that A&G costs, as reported, are not causally attributable to a particular function. Because A&G expenses are not causally attributable to a particular utility function, these expenses are not organized by function on the Form 1 in the same way that labor costs and O&M are organized.

25. 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.[23] For example, although part of a CEO's desk is devoted to distribution, transmission and production, respectively, how much desk space is causally related to each of the three functions is indeterminate.

26. 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

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

conceptual 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. 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 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.

27. The second model refinement pertains to the measurement of capital efficiency decay. 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 is a specific case of the hyperbolic model.

28. Whereas the OHS model assumes zero efficiency decline until asset retirement (e.g., a lightbulb), 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 AUC in previous proceedings.

29. Using a nation-wide sample of 65 firms, we have performed a study of U.S. electric distribution TFP over the 15-year period, 2007-2021, to derive the industry figures for the determination of *X*. The firms in the study consist of a broad sample of electric utilities that distribute electricity to end use customers across the United States. The sample covers approximately 70 percent of U.S. electricity consumers. The 15-year period strikes a reasonable 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. *X* is typically informed by a productivity study with the objective of establishing a forward-looking *X*. That is, the historic TFP study is used as a predictor of expected performance over this period.

4.2. TFP Study Results and *X* Factor for AUC's Third-Generation Price Cap PBR Plan

30. Figure 1 provides the results for our TFP study over the latest 15-year period, 2007-2021.

Figure 1
PC TFP Study Results
Output = MWh Growth

Period	Output	Input	PC TFP
2007	-	-	-
2008	-1.28%	0.27%	-1.55%
2009	-4.30%	0.08%	-4.39%
2010	3.31%	1.64%	1.66%
2011	-1.13%	0.79%	-1.92%
2012	-0.83%	0.77%	-1.60%
2013	0.13%	-2.04%	2.17%
2014	0.09%	0.27%	-0.19%
2015	0.11%	-0.57%	0.69%
2016	-0.39%	1.61%	-2.00%
2017	-1.67%	3.37%	-5.04%
2018	2.97%	5.07%	-2.10%
2019	-0.31%	0.42%	-0.73%
2020	-2.63%	-1.71%	-0.92%
2021	0.84%	0.10%	0.74%
Average	**-0.36%**	**0.72%**	**-1.08%**

The results of our distribution industry TFP study indicate an *X* factor for the Alberta third-generation price cap plan of -1.08 percent. Regarding its negative sign, provided that the *X* factor is developed on the basis of sound economic principles (e.g., it is forward-looking, based on a representative peer group of companies and satisfies the "invariance property") and does not undermine the financial viability of the regulated firm, the incentives for efficiency are independent of both the sign and magnitude of the *X* factor.[24] The AUC has previously recognized this very point:

> [T]he Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[25]

4.3. Summary

31. Total factor productivity is the appropriate method for setting the *X* factor for an indexed cap PBR plan. To establish the third-generation PBR framework in Alberta, we present a TFP model with updated data and other measurement improvements that refine the TFP study filed for the second-generation Alberta distribution utility PBR plan. The measurement improvements include adding customer accounts expenses, sales expenses and a portion of A&G expenses. The measurement improvements also include a more robust measure of capital stock known as the hyperbolic decay model. Our study computes electric distribution industry TFP growth between 2007-2021 to be -1.08 percent. On this basis, an appropriate *X* factor for EDTI is -1.08 percent.[26]

5. Benefit Sharing Mechanisms for AUC's Third-Generation PBR Plan

32. Issue 6 of the AUC's final list of issues explores the potential adoption of a benefit sharing mechanism ("BSM") for PBR3. Among other things it asks whether other jurisdictions' PBR plans include an ESM and whether there are alternatives to ESMs that would ensure customers share in the efficiency gains of PBR while preserving the utility's efficiency incentives.[27] In this section, we first provide a survey of recent ESMs that have been implemented in various PBR plans in North America. We then provide an analysis of three BSM options and appropriate associated premiums on the

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[24] Luis M. B. Cabral, and Michael H. Riordan, "Incentives for Cost Reduction Under Price Cap Regulation," *Journal of Regulatory Economics*, Vol. 1(2), June 1989, pp. 93-102.

[25] AUC Decision 2012-237, 2012, p. 104.

[26] As discussed below, the *X* factor of -1.08 percent based on the results of our TFP study is paired with a standard ESM. Other BSMs, notably an *X* factor premium and a high-powered ESM, are paired with different *X* factor premium values resulting in different composite *X* factors.

[27] Alberta Utilities Commission, "Third Generation Performance-Based Regulation (PBR3), Proceeding 27388: Ruling on Final List of Issues," September 16, 2022.

X factor for benefit sharing mechanism purposes: (1) a standard ESM, (2) an *X* factor premium, and (3) a high-powered ESM.

5.1. A Survey of Recent Earnings Sharing Mechanisms

33. Issue 6 considers whether an ESM should be introduced as a method to share benefits with Alberta Utility customers. Issue 6 also asks whether other jurisdictions' PBR plans include an ESM or alternative mechanism. In fact, a number of North American indexed PBR plans also include an ESM.

34. Two key features of ESMs are the *deadband* and the degree of *sharing* between a utility's customers and the utility's shareholders. The presence of a deadband around the utility's authorized return on equity ("ROE") establishes the basis point range of deviation of actual earnings from the authorized ROE inside of which no sharing will occur. The deadband can either be: (1) symmetric, in which case the number of basis point deviation from the authorized ROE with no sharing is the same both above and below the authorized ROE; or (2) asymmetric, in which case the deadband is different above and below the authorized ROE. In an extreme example of an asymmetric ESM, the deadband only exists above the authorized ROE. Where a deadband exists, sharing only occurs once the actual ROE exceeds the bounds of the deadband. In plans that have deadbands above and below the authorized ROE, customers and shareholders share in both the benefits of excess returns (when actual ROE is greater than the upper deadband) and also share the consequences of lower than allowed returns (when actual ROE is less than the lower deadband). Under an asymmetric ESM, where a deadband only exists above the authorized ROE, customers and shareholders share in the benefits of excess returns, but only shareholders bear the burden when actual ROE is less than the authorized ROE.[28]

35. Responsive to Issue 6, Figure 2 contains a survey of recent ESMs in various U.S. and Canadian jurisdictions. As the table illustrates, there are numerous approaches to constructing ESMs. Deadbands may be larger at one utility compared to another and may have differing levels of asymmetry. Of the PBR plans in this review, all but one utilize a deadband.

[28] Dr. Weisman analyzes the incentive properties of various ESM designs in his evidence, See Dennis L. Weisman, "Economic Tradeoffs in the Design of the Third-Generation PBR Plan," January 17, 2023.

Figure 2
Survey of Recent Earnings Sharing Mechanisms

Utility	Jurisdiction	Deadband (Basis Points)	Sharing (Customers/Shareholders)
Eversource Electric[29] 2018-2022	Massachusetts	200 above ROE	75%/25% above deadband
Eversource Gas[30] 2020-2024	Massachusetts	100 above ROE; 150 below ROE	75%/25% above deadband; 50%/50% below deadband if up to 50 below deadband and 75%/25% if more than 50 below deadband
National Grid Electric[31] 2019-2023	Massachusetts	200 above ROE	75%/25% above deadband
National Grid Gas[32] 2021-2025	Massachusetts	100 above ROE; 150 below ROE	75%/25% above deadband; 50%/50% below deadband if between up to 50 below deadband and 75%/25% if more than 50 below deadband
HECO[33] 2021-2025	Hawaii	300 above ROE; 300 below ROE	50%/50% up to 150 above deadband and 90%/10% if more than 150 above deadband; 50%/50% up to 150 below deadband and 90%/10% if more than 150 below deadband
FortisBC[34] 2020-2024	British Columbia	None	50%/50% above ROE 50%/50% below ROE
Ontario Hydro[35] 2018-2022	Ontario	100 above ROE	50%/50% above deadband

[29] Massachusetts D.P.U. 17-05.

[30] Massachusetts D.P.U. 19-120.

[31] Massachusetts D.P.U. 18-150.

[32] Massachusetts D.P.U. 20-120.

[33] Hawaii Public Utilities Commission. Docket 2018-0088. Decision and Order No. 37507.

[34] BCUC Decision and Orders G-165-20 and G-166-20.

[35] OEB Decision and Rate Order EB-2020-0030.

5.2. *X* Factor Premium

36. In addition to inquiring about ESMs, Issue 6 asks if there are

> [A]lternatives to a traditional ESM that would ensure customers have opportunities to share in efficiency gains within the PBR term while preserving the utility's incentives to maximize efficiencies and cost savings[.][36]

In particular, Issue 6 asks whether a larger stretch factor (i.e., an *X* factor premium) can be adopted as a substitute BSM for an ESM. One reason a stretch factor is typically added to the *X* factor of first-generation PBR plans is to account for the expected increase in productivity growth as an industry transitions from traditional cost of service regulation to PBR—i.e., the "low-hanging fruit." Subsequent generation PBR plans would expect to have relatively lower stretch factors for this purpose.[37] Since the *X* factor is often based on studies of historic productivity growth whose data represent a period before the industry moves to PBR, the stretch factor is seen as a forward-looking adjustment to the historically-measured productivity growth to account for the improved efficiency incentives under PBR:

> The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.[38] […] The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the "low hanging fruit") due to increased incentives.[39]

37. Moreover, as the Commission appropriately noted, the stretch factor is often based on the regulator's judgement rather than an analytical calculation, unlike the

[36] Alberta Utilities Commission, "Third Generation Performance-Based Regulation (PBR3), Proceeding 27388: Ruling on Final List of Issues," September 16, 2022.

[37] Dennis L. Weisman, "Economic Tradeoffs in the Design of the Third-Generation PBR Plan," January 17, 2023, pp. 26-27.

[38] AUC Decision 2012-237, p. 100.

[39] AUC Decision 2012-237, pp. 100-101.

measurement of TFP and the *X* factor.[40] Figure 3 provides a representative sample of stretch factors for recent PBR plans in North America. The figure shows that stretch factors in our review fall within the range of 0.0 percent (in the case of Hydro Quebec Transmission, or HQT) and 0.45 percent (in the case of Hydro Ottawa). In the case of National Grid, the stretch factor ties to inflation such that the value declines to 0.2 percent for annual inflation values below two percent, and falls to 0.0 percent for inflation under one percent. Although this table of stretch factors in other jurisdictions does not determine a definitive X factor premium value for the utilities in Alberta, it provides guidance for a reasonable range.

Figure 3

Representative Sample of Recent PBR Stretch Factors

Industry	Utility	Current Stretch Factor	Generation
Electricity	FortisBC	Integrated into X factor (1st Gen, 0.1%)	2
	Alberta	Integrated into X Factor (1st Gen, 0.2%)	2
	HQT	0.00%	1
	Hydro One	0.30%	4
	Hydro Ottawa	0.45%	4
	Alectra	0.30%	4
	HECO	0.22%	1
	Eversource	0.25%	2
	National Grid	0.4% Maximum	1
Natural Gas	FortisBC Energy Inc.	0.20%	2
	Enbridge	0.30%	3
	National Grid	0.30%	1
	Eversource	0.25%	1

38. For the first-generation PBR framework in Alberta, the AUC determined a stretch factor of 0.2 percent.[41] For the second-generation framework, the AUC also included a stretch factor. However, the Commission did not distinguish between the *X* factor and the stretch factor in its combined 0.30 percent *X* factor/stretch factor for its second-generation plan.[42] This combined second-generation *X* factor/stretch factor is 74 percent less that the first-generation combined *X* factor/stretch factor of 1.16 percent. Assuming the Commission reduced the *X* factor and the stretch factor values

[40] AUC Decision 2012-237, p. 104. "[T]he determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a 'definitive analytical source' like the TFP study represents."

[41] AUC Decision 2012-237, p. 104.

[42] AUC Decision 20414-D01-2016, p. 45.

proportionately from the first generation to the second generation, this suggests a stretch factor for the second-generation PBR regime of 0.052 percent. As stretch factors would generally be expected to decline over time, since the low-hanging fruit has largely been picked, this stretch factor would tend to overstate the appropriate stretch factor for that purpose for a third-generation PBR regime.

39. We are advised by EDTI that, based on the economic logic of stretch factors, EDTI is proposing an *X* factor premium of 0.30 percent for the third-generation PBR plan, 50 percent higher than the AUC-determined first-generation stretch factor, and almost six times greater than the implied AUC second-generation stretch factor. This *X* factor premium would be added to the computed *X* factor (that would be paired with a standard ESM, as a standard ESM reflects the relatively low powered incentive regimes applicable to the vast majority of the 65 firms in our TFP sample) to obtain a composite "premium" *X* factor that would not be paired with an ESM. With a computed *X* factor of -1.08 percent and a proposed *X* factor premium of 0.30 percent the composite *X* factor, including the premium, is -0.78 percent. Based on the economic logic of stretch factors, and given the range of stretch factors across other PBR plans, we believe EDTI's proposed *X* factor premium is reasonable and an appropriate BSM for PBR3.

5.3. High-Powered ESM

40. As an alternative to the *X* factor with a standard ESM and no ESM with an *X* factor premium added to the computed *X* factor, Dr. Weisman develops a high-powered ESM ("HP-ESM") as a means of sharing benefits with consumers. The HP-ESM would be paired with a composite *X* factor that includes a premium, but this *X* factor premium would be smaller than the one included in the composite *X* factor that is not paired with an ESM. Dr. Weisman describes the HP-ESM in his evidence and notes that, "One prospective advantage of this type of ESM relative to the standard ESM discussed above is that it provides more high-powered incentives for cost-reducing innovation."[43]

41. The logic of establishing the composite *X* factor that includes a premium to be paired with the HP-ESM is as follows. If the *X* factor premium is 0.30 when the utility retains

[43] Dennis L. Weisman, "Economic Tradeoffs in the Design of the Third-Generation PBR Plan," January 17, 2023, p. 20.

100 percent of each dollar in cost savings as under the *X* factor premium approach with no ESM, a reasonable approximation is that the utility will retain 80 percent of each dollar in cost savings if there is an HP-ESM in place.[44] Thus, the premium for benefits sharing purposes should be 0.8 x 0.30 when it retains only 80 percent of each additional dollar in cost savings. Adding this to the computed *X* factor of -1.08 percent results in a composite *X* factor (i.e., combined *X* factor and *X* factor premium) of -0.84 percent when there is an HP-ESM as part of the PBR plan (-0.84 = -1.08 + (0.8 x 0.30)).

5.4. Summary

42. To summarize, the value of the composite or final *X* factor in the AUC's third-generation PBR plan depends on the existence and type of BSM that is part of the plan. Figure 4 summarizes the relationship between the -1.08 percent *X* factor computed in our study, the type and existence of an BSM, and adjustments to this *X* factor that provide additional consumer benefit during the PBR term to arrive at the final, composite *X* factor. As Figure 4 indicates: (1) in the case of a standard ESM, all additional consumer benefit flows through the ESM and there is no *X* factor adjustment, so the composite *X* factor is -1.08 percent; (2) if there is a high-powered ESM and additional consumer benefit consisting of a 0.24 percent *X* factor premium, the composite *X* factor is -0.84 percent; and (3) if there is no ESM, the *X* factor premium proposed by EDTI that provides additional consumer benefit of 0.30 percent results in a composite *X* factor is -0.78 percent.

Figure 4

Summary of *X* Factor/ESM Combinations

ESM Status	Computed *X*	Additional Consumer Benefit	Composite *X*
Standard ESM	-1.08%	0.00%[45]	-1.08%
High-Powered ESM	-1.08%	0.24%	-0.84%
X Premium, No ESM	-1.08%	0.30%	-0.78%

[44] This would be consistent, for example, with an 80 percent probability of company returns within the deadband, and a 20 percent probability of earnings within the first tier of the ESM, where the effective earnings tax is 100%, ceteris paribus.

[45] Aside from the standard ESM, there is no increase in the *X* factor from its computed value under this option; all additional consumer benefit flows through the standard ESM under this option.

6. Conclusion

43. The TFP growth or *X* factor computed by our TFP study is -1.08 percent. This value reflects a refined version of the TFP model filed in prior Alberta PBR proceedings, which incorporates customer account expenses, sales expenses, a portion of A&G expenses, and a more robust measurement of capital stock. It is assumed that this computed *X* factor would be paired with a standard ESM for the third-generation AUC PBR plan.

44. With respect to the AUC's inquiry regarding use of a stretch factor BSM (i.e., *X* factor premium) as an alternative to ESMs, we have provided an approach based on both an analysis of company data and expert judgement that derives a reasonable *X* factor premium, which works to directly provide consumer benefits in lieu of an ESM. EDTI is proposing a value of 0.30 percent for the *X* factor premium. This premium falls within the industry range, is 50 percent greater than the first-generation AUC stretch factor, and is almost six times the implied second-generation AUC stretch factor. We believe EDTI's proposed premium is reasonable and is an appropriate BSM for PBR3. Adding this premium to the computed *X* factor noted above results in a composite *X* factor of -0.78 percent under a PBR framework with no ESM. Alternatively, under the high-powered ESM developed by Dr. Weisman, the premium would be 0.24 percent, resulting in a composite *X* factor of -0.84 percent.

Appendix A: Total Factor Productivity Study Methodology

Overview

A cap formula sets a ceiling on prices (i.e., price cap) or revenues (i.e., revenue cap or revenue per customer cap). This cap or ceiling restricts prices (or revenues) to be at or below a predetermined level, typically based on some measure of economic performance that is external to the regulated firm and cannot be manipulated by the firm. Generally, the cap has the form of "I – X," where I is a measure of inflation and X is a measure of expected productivity growth over the PBR term that is external to the regulated firm and is typically representative of some industry average.[46] This appendix describes the computation of total factor productivity (TFP) that is the basis of the price cap X factor.

Price Cap Mechanics

Under price cap regulation, the prices that can be charged by the regulated firm are governed by a formula that effectively limits changes in prices to some measure of inflation, adjusted for the regulated industry's ability to offset inflation with gains in productivity—i.e., the "I – X" formula sets a ceiling on price changes for services that are subject to the price cap. The price cap approach to regulation is based on the proposition that in competitive markets the prices charged for a product or service are determined by the prices of the inputs used to produce the product or service, adjusted for any productivity gains exhibited in combining those inputs to produce the product or service. This formula essentially mimics the change in average industry unit costs and, thus, price changes are capped by the expected change in average industry unit costs. The price cap formula has the general form:[47]

$\%\Delta P = (I - X)$

Where

$\%\Delta P$ = allowed change in capped price (or index of prices)

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[46] The parameters included in X depend on the specification of the inflation term, I. If I is a measure of industry input prices, X is determined by expected industry productivity growth. 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 expected productivity growth between the industry and the overall economy, and a differential in input price growth between the overall economy and the industry.

[47] The (I – X) formula is often supplemented with a "Z factor" that allows the cap to be adjusted for one-time factors that are outside the control of the regulated firm and that are not already reflected in the cap formula. The basic principle is that the regulated firm should not unduly benefit from nor be unduly harmed by events that are outside of its control (i.e., exogenous).

I = inflation factor
X = productivity growth

The price cap formula encourages the firm to behave more efficiently by providing an incentive to cut costs.

For a particular company, the inflation and productivity indices serve as proxies for the growth in per-unit costs that the company should have experienced during the specified period, if it were an average-performing company. A company that achieved lower-than-average growth in per-unit costs during this period would be rewarded under a price-cap regulation, as it would have the opportunity to earn additional profits. Conversely, a company whose growth in per-unit costs exceeded the average might realize lower-than-anticipated profits.[48]

The Measure of Productivity Growth that is the Basis of the X Factor

The productivity measure typically used to generate an X factor for a price cap is total factor productivity ("TFP"). TFP is generally defined as the ratio of total output to total input:

TFP = Total Output/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. The correct specification of output for a TFP 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.

When the purpose of TFP measurement is for use in calibrating the X factor for a price cap (i.e., PC TFP), the output measure should reflect the elements of output associated with customer prices or revenue generation—i.e., billed output—because those are the elements of output whose prices are being constrained by the cap.[49] In general, these are not the same elements of the output that would be used in an efficiency measure of TFP since the billed output measure would include only those aspects of output produced by the firm or industry that are explicitly related to customer prices subject to the cap. In most cases, billed output would be a proper subset of the total output produced. In the case of a price cap, a

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[48] D.T.E. 03-40, October 31, 2003, p. 474.

[49] For example, see Laurits R. Christensen, Philip E. Schoech, and Mark E. Meitzen, "Total Factor Productivity in the Telecommunications Industry," in *International Handbook on Telecommunications Economics*, G. Madden and S. Savage, eds., 2003.

more accurate description of TFP for this purpose would be the ratio of billed output to total input. Defining this measure of TFP as price cap TFP (PC TFP = TFP^P):[50]

$$TFP^P = Billed\ Output/Total\ Input$$

TFP is widely recognized as a comprehensive measure 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:

$$\%\Delta TFP = \%\Delta Total\ Output - \%\Delta Total\ Input$$

Or, in the case of PC TFP that is a component of an X factor:

$$\%\Delta TFP^P = \%\Delta Billed\ Output - \%\Delta Total\ Input$$

For example, if TFP growth is equal to 2.0%, this means that the same output can 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.

Output: Customer Billing Elements

When the purpose of TFP measurement is for use in calibrating the X factor for a price cap (i.e., PC TFP), the output measure should reflect the elements of output associated with customer prices or revenue generation—i.e., billed output—because those are the elements of output whose prices are being constrained by the cap. While the billing elements for electric distribution are comprised of both volumetric and non-volumetric measures (e.g., usage and connection charges), to determine a proper measure of industry output reflecting these components, the proportions of volumetric and non-volumetric charges for all firms in the industry sample over all years in the sample would need to be known. In most price cap TFP studies for the electric distribution industry, including those studies that have been the basis of AUC decisions for previous generations of Alberta PBR, billed output is represented by the growth in MWh.

[50] Another difference between the efficiency and PC measure of TFP is how the various elements of output are weighted together to construct the relevant output index. Also, as discussed below, billed output is likely to be a proper subset of total output as customers are not billed for all of the outputs produced by the utility. Moreover, this difference has likely been increasing over recent years.

Input: 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,[51] with the quantity index of labor derived by dividing the cost of labor by its price.

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

Input: 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:

Figure A.1

FERC Accounts used for Customer Accounts & Sales

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

[51] 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/)

Statistics Employment Cost Index for utility industry wages and salaries,[52] 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). 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.

Input: 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. The economic literature recognizes that there is not a unique, economically causal method to allocate joint and common costs.[53] Allocations of joint and common costs are arbitrary from an economic perspective because it cannot be determined from available data 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.

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[52] 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/)

[53] 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).

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:

Figure A.2

FERC Accounts used for Administrative & General Expenses

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,[54] 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.

[54] 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/).

Input: 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 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.[55] 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

[55] 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.

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 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 2007. To estimate capital input for the year 2007, we need an end of year capital stock estimate for 2006. That in turn requires projections of investment back to 1941, 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,[56] and applying it to net electric plant in service.[57] 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 2007 through 2021.

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

[56] 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.

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

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 U.S. 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.[58] We apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2007-2021 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.[59] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[60]

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[58] 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.

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

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

Total Input

We construct the quantity index of total input for each firm and each year by using the multilateral Tornqvist indexing procedure.[61] 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 = 2007 … 2021)

j = input (j = 1 … 7)[62]

$X_{i,t}$ = 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:

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

Where

i = firm (i = 1 … 65)

t = period (t = 2007 … 2021)

j = input (j = 1 … 7)

$P_{i,t}$ = 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.

[61] 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.

[62] 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.

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 its annual output in megawatt-hours (MWh). Denoting output by MWh, the weighting factors for each firm are computed as follows:

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

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

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

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 PC TFP growth is the difference between the industry rate of total output growth (given by the growth in MWh) 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

The national sample consists of 65 firms. 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

Figure A.4

FERC Form 1 Data Sources

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

	Line Number
Distribution	20
Distribution	23
Customer Accounts	21
Customer Accounts	24
Sales	23
Sales	26
Administrative and General	24
Administrative and General	27

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

	Line Number
Total Power Production Expenses	80
Total Power Production Expenses	80
Total Transmission Expenses	100
Total Transmission Expenses	112
Total Distribution Expenses	126
Total Distribution Expenses	156
Uncollectible Accounts	132
Uncollectible Accounts	162
Total Customer Account Expenses	134
Total Customer Account Expenses	164
Franchise Requirements	159
Franchise Requirements	188
Maintenance of General Plant	167
Maintenance of General Plant	196
Total Administrative and General Expenses	168
Total Administrative and General Expenses	197
Total Electric Operations and Maintenance Expenses	169
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

Appendix B: Resumes of Mark E. Meitzen and Nicholas A. Crowley

Mark E. Meitzen

RESUME

January 2023

Address:

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Academic Background:

PhD, University of Wisconsin–Madison, 1982, Economics
MS, University of Wisconsin–Madison, 1979, Economics
BS, University of Wisconsin–Oshkosh, 1976, Economics

Positions Held:

Senior Consultant, present
Vice President, Laurits R. Christensen Associates, Inc., 1998–2016
Director-Telecommunications, Laurits R. Christensen Associates, Inc., 1993–1998
Senior Economist, Laurits R. Christensen Associates, Inc., 1990–1993
Regulatory Economist, Southwestern Bell Telephone Company, 1988–1990
Regional Economist, Southwestern Bell Telephone Company, 1986–1988
Adjunct Faculty, Saint Louis University, St. Louis, Mo., 1987–1990
Visiting Assistant Professor of Economics, University of Wisconsin-Milwaukee, 1984–1985
Assistant Professor of Economics, Eastern Michigan University, 1981–1984

Professional Experience:

I have expertise in the economic analysis of network industries including telecommunications, electricity, postal and railroad. This experience includes cost and productivity analysis, and the design of incentive regulation plans. I have directed analyses and testified in a number of jurisdictions in the U.S. and elsewhere on these issues, including the Federal Communications Commission, the Alberta (Canada) Utilities Commission, OSIPTEL (Peru), and the U.S. Surface Transportation Board. I also have experience as an expert witness on economic damages in civil litigation cases on a range of issues, including antitrust, intellectual property, breach of contract, and employment issues.

Publications:

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"Differential Compensation and Worker Turnover," *Journal of Economics*, 1989, (with L. Brannman).

"Differences in Male and Female Job Quitting Behavior," *Journal of Labor Economics*, 1986.

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"Empirical Analysis of the Rate of Worker Separation," in *Subsidizing On-the-Job Training*, Columbus, OH: National Center for Research in Vocational Education, 1982.

Presentations at Workshops and Professional Meetings:

"PBR in the Electric Utility Industry," EUCI, November 2021.

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"Adoption of Broad-Based PBR Indexing Plans in Electric Distribution," Wisconsin Public Utilities Institute, July 2017 (with Dennis Weisman).

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"Preserving and Protecting Freight Infrastructure and Routes, Findings from NCFRP 24," Federal Highway Administration, Talking Freight Seminar, August 2011.

"Preserving and Protecting Freight Infrastructure and Routes," NCFRP24 Workshop, January 2011.

"Preserving and Protecting Freight Infrastructure and Routes," Minnesota Freight Advisory Committee, October 2010.

"An Update to the Study of Competition in the U.S. Freight Railroad Industry," Midwest Association of Rail Shippers, July 2010.

Overview of the Christensen Associates' Railroad Industry Studies," National Coal Transportation Association, September 2009.

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"A Study of Competition in the Railroad Industry and Analysis of Proposals to Enhance Competition, A Progress Report," Midwest Association of Rail Shippers, January 2008.

"Economics of Price Erosion Using Available Data," Law Seminars International Patent Damages Workshop, Chicago, IL, April 2004.

"Economics of Price Erosion and Lost Convoyed Sales Using Available Data," Law Seminars International Patent Damages Workshop, Chicago, IL, April 2003 (with J. Cordray).

"Local Exchange Competition," Wisconsin Public Utility Institute, Madison, WI, April 2003.

"Patent Damages: Analyzing the Market But-For Infringement," presented to the Milwaukee Bar Association's Intellectual Property Section, May 2000, (with C. Degen).

"Implementation of Price Cap Regulation–The FCC Experience," Wisconsin Public Utility Institute, Madison, WI, September 1999.

"Costs of Universal Service," Wisconsin Public Utility Institute, Madison, WI, March 1997.

"Unbundled Network Elements and Economic Cost Standards," Wisconsin Institute of Certified Public Accountants, Madison, WI, October 1997.

"The Uses and Abuses of Stand-Alone Costs," Second Prize winner in the Research Awards Competition of the Eleventh Annual Southeastern Public Utilities Conference, Atlanta, GA, September 23, 1991.

"Diversification of Telephone Company Service Offerings and Cash Cow Economics: Who Gets Milked?" First Prize winner in the Research Awards Competition of the Tenth Annual Southeastern Public Utilities Conference, Atlanta, GA, August 1990. Also presented at the Third Annual Western Conference of the Rutgers University Advanced Workshop in Regulation and Public Utility Economics, San Diego, CA, July 1990.

"Financial Market Implications of Competition and Regulation in the Telecommunications Industry," Eighth Annual Conference of the Rutgers University Advanced Workshop in Regulation and Public Utility Economics, Newport, RI, May 1989.

"Foreign Trade in Telecommunications Equipment," Second prize winner in the papers competition held in conjunction with the Eleventh Annual Midwestern Telecommunications Conference, Minneapolis, MN, October 1988.

"Perspectives on Local Exchange Competition," Presented at the Seventh Bi-Annual Conference of the International Telecommunications Society, Cambridge, MA, June 1988.

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"The Role of Voice Mechanisms in Workers' Participation in and Satisfaction with Unions," 1984 Midwest Economics Association Convention, Chicago, IL.

"Hedonic Wage Models and Worker Turnover," 1984 Midwest Economics Association Convention, Chicago, IL.

"The Impact of Unionism on Exit and Voice Decisions in the Labor Market," 1984 Missouri Valley Economics Association Convention, Kansas City, MO, (with S. Hayworth).

"Differences in Male and Female Job Quitting Behavior," 1983 Midwest Economics Association Convention, St. Louis, MO.

Non-Confidential Consulting Reports and Research Papers:

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, June 10, 2022.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, January 14, 2022.

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Client: Coal Shippers Coalition (2006)
Proceeding: Surface Transportation Board Ex Parte No. 657 (Sub-No. 1)

Client: AEP Texas North (2004)
Proceeding: Surface Transportation Board Docket No. 41191

Client: OSIPTEL (2003)
Proceeding: TdP Price Cap Implementation (Peru)

Client: OSIPTEL (2002)
Proceeding: TdP Price Cap Implementation (Peru)

Client: OSIPTEL (2001)
Proceeding: TdP Price Cap Implementation (Peru)
Client: Ameritech Illinois (2001)
Proceeding: ICC Docket No. 98-0252

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Proceeding: Surface Transportation Board Docket No. 42056

Client: Reliant Energy HL&P (2000)
Proceeding: Texas SOAH Docket No. 473-00-1020, Texas PUC Docket No. 22355

Client: Frontier Communications (1999)
Proceeding: MPSC Case No. U-12049

Client: TDS Telecom (1998)
Proceeding: MPSC Case No. U-11815

Client: Mid-Plains Telephone (1997)
Proceeding: PSCW Dockets 3650-MA-100 and 5845-MA-100

Client: Washington Independent Telephone Association (1997)
Proceeding: WUTC Docket UT-960369

Client: Michigan Exchange Carriers Association (1997)
Proceeding: MPSC Case No. U-11448

Client: Wisconsin State Telephone Association (1996)
Proceeding: PSCW Docket 05-TI-137

Client: Ameritech Illinois (1995)
Proceeding: ICC Docket 95-0458

Client: Southwestern Bell Corporation Media Ventures (1994)
Proceeding: Maryland PSC Docket 8659

Client: Ameritech Illinois (1993)
Proceeding: ICC Docket 92-0211

Client: Urban Telephone Company (Wisconsin) (1992)
Proceeding: PSCW Docket 6050-TI-100

Nick Crowley

RESUME

December 2022

Address:

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Academic Background:

Master of Science – University of Wisconsin-Madison, 2014, Economics
Bachelor of Arts – University of Wisconsin-Madison, 2012, Economics

Positions Held:

Senior Economist, Laurits R. Christensen Associates, Inc., Sept. 1, 2021-presernt
Economist, Laurits R. Christensen Associates, Inc., 2019-Aug. 31, 2021
Staff Economist, Laurits R. Christensen Associates, Inc., 2016-2018
Economist, Federal Energy Regulatory Commission, 2015-2016

Professional Experience:

I have extensive experience in matters of utility regulation, with an emphasis on rate design, regulatory finance, and productivity measurement. In my time as a consultant, I have testified on behalf of a major public utility in contentious rate proceedings, measured cost of capital and assembled corresponding reports, developed alternative rate designs, and forecasted electricity load for supply planning purposes. I have also performed extensive research for benchmarking purposes using publicly available data. My work includes marginal cost estimation and the development of marginal cost models for major electric utilities. On an ongoing basis, I manage a team to measure the price response by customers participating in leading demand response programs. My reports have been filed before regulatory authorities across North America. Prior to joining Christensen Associates Energy Consulting, I served as an Economist at the Federal Energy Regulatory Commission, where I assisted with energy industry benchmarking, market power studies, and the review and evaluation of natural gas pipeline rate cases. I have deep facility with Stata and Excel, in addition to other software packages used in quantitative analysis.

PUBLIC TESTIMONY

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, June 10, 2022.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, January 14, 2022.

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, April 23, 2021.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, November 13, 2020.

PUBLICATIONS

"2021 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Aidan Glaser-Schoff)

"Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities." *Utilities Policy.* Vol. 72, October 2021. (with Dr. Mark Meitzen)

"2020 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Navya Kataria)

"2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2018 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

"2017 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: Ex-post and Ex-ante Report for Customers with Net Energy Metering." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

CONFERENCE PRESENTATIONS

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 4, 2022.

"Rate Innovation for Cooperatives and Public Power." EUCI Workshop. Virtual. March 2022.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. March 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. February 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. November 2021.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 2, 2021.

"Rate Design and the Potential Impacts of Covid-19." EUCI Workshop. Virtual. November 17, 2020.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Atlanta, Georgia. March 9, 2020.

"Load Impact Evaluation: *Base Interruptible Program*." DRMEC Spring Workshop, California Public Utilities Commission. April 26, 2019.

"FERC Regulatory Policy and Relevant Environmental Issues, Focusing on the United States Natural Gas Grid" at the University of Wisconsin for the 2015 Energy Hub Conference.

REPORTS AND WORKING PAPERS

"A New Way Forward: Assuming Hyperbolic Capital Decay in Measuring Electric Distribution Capital Stock." (Working paper with Dr. Kevin Roth.)

"Cost of Capital Study." For Grand Bahama Power Company, Ltd. April 15, 2021.

"Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029." For Newfoundland and Labrador Hydro. November 15, 2018.

"Cost of Capital Study." For Grand Bahama Power Company, Ltd. October 17, 2018.

"Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period." *Federal Energy Regulatory Commission Staff Report,* 2016.

COMPUTER/PROGRAMMING SKILLS: Deep knowledge of Excel and STATA for data analysis; experience with R, SAS, and Python for API data acquisition and manipulation.