Review of Total Cost Benchmarking Methodology for Electricity Distributors[1]

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Executive Summary

1. Introduction

This report reviews the Ontario Energy Board (OEB) total cost benchmarking methodology for electricity distributors. The work is a collaboration between the University of Toronto's Economics Department and the OEB; and is funded by the OEB and Climate Positive Energy at the University of Toronto. The project addresses methodological issues, particularly the statistical benchmarking approach used by the OEB, explores alternative approaches and benchmarking practices in other jurisdictions, conducts an extensive literature review and identifies observations and considerations for modifications. A separate and closely related report conducts statistical analyses of distributor cost benchmarking.

The vision of the OEB is "To be a trusted regulator who is recognized for enabling Ontario's growing economy and improving the quality of life for the people of this province who deserve safe, reliable and affordable energy." Its stated mission is "To deliver public value through prudent regulation and independent adjudicative decision-making which contributes to Ontario's economic, social and environmental development."[2] Within this context, the OEB has regulated electricity distribution utilities for a quarter of a century. The OEB turned to incentive regulation early and developed a systematic framework for regulating numerous utilities, promoted energy conservation, encouraged efficiency gains through mergers and acquisitions, held major stakeholder consolidations, maintained an 'open data' process, and most importantly, ensured that 'the lights stayed on'. The OEB's use of data-based approaches as tools for informing the regulation of a diverse and disparate set of utilities is at the leading edge, globally.

The landscape of electricity industries is being transformed as we move into an energy transition driven by decarbonization, digitization, and decentralization. Arguably, electricity industries are also experiencing a degree of democratization as small-scale alternatives compete with conventional systems. Electricity distribution companies are evolving from distributing electricity and providing energy services, to actively managing bi-directional energy flows, integrating distributed energy resources (DERs), and adapting to changes in consumption patterns. Their activities include managing the growing adoption of electric vehicles (EVs), the electrification of heating, and incorporation of new digital and smart grid technologies which require significant upgrades to infrastructure and operations. As we move further into the energy transition, one of the explicitly stated guiding lights should be promoting and *incentivizing* innovation. Electric utilities tend to be risk-averse, but incremental technological change and game-changing breakthroughs inevitably involve projects that fail and other projects that succeed. Promoting change requires support from the Government and a willingness and incentives for distributors to take risks.

[2] See Ontario Energy Board "Mission and mandate" https://www.oeb.ca/about-oeb/mission-and-mandate.

2. Background

In settings with multiple regulated entities, as is the case in Ontario, 'yardstick competition' and benchmarking are useful tools. The OEB has relied primarily on Total Cost Benchmarking (TCB), a detailed statistical procedure, to analyze differences among distributors and predict costs, and to a lesser degree on Total Factor Productivity (TFP) calculations. TFP relates changes in outputs to changes in inputs where output growth is not necessarily the result merely of changes in input quantities, but of more efficient use of those inputs.

The report surveys incentive regulation and benchmarking of productivity and reliability across various jurisdictions in Europe, the USA, Australia and Canada. It contains an extensive literature review organized around several themes including the evolving roles of electricity distributors, incentive regulation, and benchmarking efficiency. It highlights the challenges in benchmarking in an evolving technological and regulatory landscape, noting the challenges in setting clear benchmarks due to utilities' expanding responsibilities, such as grid modernization and integration of renewables. The review emphasizes the need for innovation and dynamic efficiency in the rapidly changing energy sector, suggesting that traditional measures of static efficiency may be insufficient.

Integrating reliability metrics such as outage frequency and duration within benchmarking models incentivizes service quality improvement while maintaining cost efficiency. Various continental European countries, the United Kingdom, and Australia incorporate financial incentives tied to reliability targets to ensure distributor accountability and to enhance service quality. Network security is emerging as an increasingly important area for ensuring grid resilience against cybersecurity threats.

The report then turns to a more detailed evaluation of commonly used methodologies for assessing costs and productivity, including Total Cost Benchmarking (TCB), Total Factor Productivity (TFP), Data Envelopment Analysis (DEA), and Stochastic Frontier Analysis (SFA). In addition, there is a discussion of Multilateral Total Factor Productivity, Partial Performance Indicators, and Activity and Program Based benchmarking. Each methodology has strengths and limitations as a result of data availability, the need to account for external conditions, and the complexity of the energy distribution landscape.

3. Evaluation of the Current TCB Methodology

The TCB model assesses the cost efficiency of Ontario electricity distributors by employing econometric techniques. The model incorporates various business conditions such as customer base, input prices and other factors. These conditions influence total costs which are modeled using parameters derived from Ontario distributor data spanning 2002 to 2012. Despite its apparent sophistication, the TCB model can be estimated using standard econometric software.

The TCB model includes a trend term coefficient which plays a critical role in estimating productivity growth. A negative coefficient indicates positive productivity growth where the costs of producing a given level of service declines over time. However, in the EB 2010-0379 consultation, the Pacific Economics Group and the Electricity Distributors Association found a positive coefficient, suggesting negative measured productivity growth. This apparent anomaly may have been due to the absence of relevant data, increasing costs of providing service, attenuated consumption growth, and a changing industry environment including government policies such as the mandated installation of smart meters.

The TCB model projects total costs for each distributor by multiplying the company's business condition variables by the model parameters and summing the results. Distributors are then compared based on their actual costs versus predicted costs, with those performing below predicted levels deemed superior in cost performance. Stretch factors are assigned based on this relative efficiency, recalculated annually using updated data. Distributors with costs 25% or more below predicted levels receive the lowest stretch factor of 0%, while those exceeding predicted costs by 25% or more receive the highest factor of 0.60%. The stretch factors adjust the permitted rate increases through the incentive regulation formula:

$$Price\ Cap\ Adjustment\ (PCA) = Inflation - (Productivity + Stretch\ Factor).$$

Since 2013, the TCB model parameters have remained unchanged in order to provide a consistent benchmark for distributors. However, it is now an opportune time to re-estimate the model with a decade of additional data. Potential modifications include flexible econometric modeling, such as semiparametric techniques, which can capture complex and nonlinear relationships and improve the precision of cost function estimation.

Interjurisdictional comparisons of productivity growth can offer valuable insights, allowing for the identification of best practices and evaluation of policies aimed at promoting productivity. These comparisons can highlight areas for improvement and guide technology transfer initiatives. Data from other jurisdictions, such as the U.S., have been used in benchmarking Ontario distributors, underscoring the benefits of a broader data set. The Australian Energy Regulator, for example, incorporates Ontario distributor data into their benchmarking analyses along with data from New Zealand under the rationale that their data lacks sufficient variability.[3] Expanded use of interjurisdictional data could be beneficial in the Ontario setting.

[3] Australian Energy Regulator (2023, November). 2023 Annual Benchmarking Report: Electricity distribution network service providers (p. 92). https://www.aer.gov.au/system/files/2023-11/2023%20Annual%20Benchmarking%20Report%20–%20Electricity%20distribution%20network%20service%20providers%20–%20November%202023.pdf.

The calculation of stretch factors could also be modified to include components reflecting reliability and service quality. Additionally, stretch factors could recognize improvements in utility performance relative to their own past performance.

Advantages and Disadvantages of Total Cost Benchmarking	
Advantages	Disadvantages
Attribution of cost effects to specific factors	Requires extensive, high-quality consistent data
Separate identification of scale, scope, and technology effects	May be technically complex for non-experts
Standard statistical techniques	Results sensitive to modeling assumptions
Basis for estimating output weights for TFP	May oversimplify distribution system complexities
Flexible model structure	Limited focus on service quality and customer satisfaction
Statistical testing capabilities	
Incorporation of random effects	

An alternative to Total Cost Benchmarking is peer group analysis which requires allocating each utility to a group of 'peers'. However, this approach can suffer disadvantages as peer group assignment may be arbitrary or even produce disincentives as utilities seek assignment to more advantageous peer groups.[4]

Technical Sophistication and Regulatory Costs

Electricity distributors can choose from three incentive rate-setting (IR) methodologies: Price Cap IR, Custom IR, and Annual IR Index. Most utilities opt for Price Cap IR to avoid extensive regulatory reviews, reducing the regulatory costs for themselves and for the OEB. Approximately 50 utilities, serving one-third of Ontario customers, choose the Price Cap IR stream.

A few larger utilities, in particular, Hydro One Networks Inc., Toronto Hydro-Electric System Limited, and Hydro Ottawa Limited, serving about two-thirds of Ontario's customers, have

[4] Peer group assignment also limits the number of distributors that can be compared, reducing the statistical benefits of having a larger data set for estimation of business condition effects.

chosen Custom IRs.[5] One of the predecessors to Alectra, PowerStream Inc., also chose a Custom IR. These processes involve significant resource expenditures. Hydro One Networks Inc. submits statistical analyses using U.S. utility data due to its unique status and vast geographical coverage.[6] Toronto Hydro's analyses also rely on U.S. data, which may produce different results from those of the OEB's Total Cost Benchmarking model.[7] Hydro Ottawa provides additional key performance indicators, but does not use a separate benchmarking model. This suggests the need for reconciliation and consideration of additional data sources. The Board may consider opportunities for enhancements:

- It would be helpful if the discrepancies between the Custom IR benchmarking analyses and those obtained using TCB were better understood, or even reconciled.

- It may be appropriate to incorporate at least some Ontario distributors into these models, if this has not already been done.

- It may be appropriate to incorporate data from other jurisdictions into the OEB benchmarking models as well as into the models used in Custom IR applications.

Given the very substantial regulatory costs of the Custom IR proceedings, additional possibilities for streamlining the process could be explored. There is a trade-off between technical sophistication and regulatory costs.

Does Yardstick Competition/Regulation Work?

The terms 'yardstick competition' and 'yardstick regulation' are often used interchangeably, but there are important differences. Yardstick competition involves comparing the performance of similar entities to encourage better performance, with transparent and widely available performance measures influencing stakeholders, customers, policymakers, and investors. Utilities and firms in many industries engage in yardstick competition. Yardstick regulation formalizes this process within the regulatory framework, incorporating performance measures into the rewards and penalties imposed by the regulator. Total cost benchmarking is one method for comparing utility cost performance. Although statistical benchmarking is not perfect, it has been refined over the years through improved data collection and standardization.

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[5] Some Custom IR participants have requested custom stretch factors. Ontario Energy Board (2022, December 8). Decision and Rate Order, EB-2022-0042. Hydro Ottawa Limited https://hydroottawa.com/sites/default/files/2022-12/EB-2022-0042_dec_rate%20order_Hydro%20Ottawa_20221208_signed.pdf.

[6] Hydro One Networks Inc. (2021, August 5). Custom IR Application (2023-2027) for Hydro One Networks Inc. Transimssion and Distribution – Application and Evidence. https://www.hydroone.com/abouthydroone/RegulatoryInformation/JointRateApplications/Documents/HONI_Appl_Exhibit%20A_20210805.pdf.

[7] Toronto Hydro-Electric System Limited (n.d.). EB-2023-0195. Exhibit 1A. Exhibit List / Table of Contents. https://www.torontohydro.com/documents/d/guest/exhibit-1a-administration.

In many jurisdictions, reliability data are systematically collected and sometimes incorporated into incentive regulation mechanisms, positively impacting supply continuity and reliability. Activity and program-based benchmarking also enable utilities to compare specific cost areas against each other. Studies on the design and effectiveness of incentive regulation have shown improvements in productivity and service

Yardstick competition and regulation in the utilities sector has generally been beneficial, fostering a form of indirect competition that encourages efficiency and cost-effectiveness. Properly implemented, it can promote innovation as utilities strive to outperform their peers by investing in new technologies and processes. Transparency and accountability are enhanced through the publication of performance metrics, promoting accountability to regulators, consumers and other stakeholders.

However, the benefits of yardstick regulation come with challenges. Accurate and fair benchmarking requires reliable data, and differences in regional conditions can complicate comparisons. Despite these challenges, the overall impact of yardstick competition on utilities has been positive, leading to improved efficiency, cost reduction, and enhanced service quality. In Ontario, since the 4th generation incentive regulation mechanism (4GIRM) consultation, the electricity distribution sector "has shown consistent year-over-year cost performance improvements."[8]

5. Summary of Observations and Possible Considerations for the OEB

The report suggests a number of directions which the Board may consider, should it undertake a review of its benchmarking and incentive regulation model:

- **The Total Cost Benchmarking (TCB) Model Should be Re-Estimated Using More Recent Data:** The TCB model, estimated in 2013, uses data for the period 2002-2012 (later updated to included 2013). The existing model should be re-estimated to include data for the years 2014 -2023.

- **Modifications to the TCB Model Should Be Explored:** Possible variations include incorporating nonlinear specifications, particularly for the productivity trend term; using alternate techniques to evaluate the precision of parameter estimates; and, examining sub-periods to assess whether there are shifts (known as structural breaks) in the mechanisms driving costs. Sensitivity analyses should be conducted.

[8] Pacific Economics Group (2024, July). *Empirical Research in Support of Incentive Rate-Setting, 2023 Benchmarking Update: Report to the Ontario Energy Board* (p. 8). https://www.oeb.ca/sites/default/files/PEG%20Report%20to%20the%20Ontario%20Energy%20Board%202024.pdf

- **The Inclusion of Additional Variables in the TCB Model Should be Considered:** The energy transition is changing distribution cost drivers. These include the proliferation of distributed energy resources and the increasing need for electric vehicle charging stations. Data which quantify these changes could be collected and incorporated within the TCB framework. Variables measuring service quality and reliability should also be considered.

- **Alternative Productivity Estimation Techniques Should be Explored: '**Stochastic frontier analysis' (SFA) and 'data envelopment analysis' (DEA), both of which are used in other jurisdictions, should be explored.

- **Total Factor Productivity (TFP):** The use of TFP within the X factor should be reconsidered. Additional techniques could be assessed, including 'Multilateral Total Factor Productivity', 'Partial Performance Indicators', and 'Activity and Program-Based Benchmarking'.

- **The Use of Data from Other Jurisdictions Could Be Considered.** It may be beneficial to incorporate data from other jurisdictions, either from other provinces, or jurisdictions outside Canada. As noted, the Australian Energy Regulator has used Ontario distributor data for its benchmarking analysis.

- **Systematic Comparisons of Ontario Distributor Productivity Growth to Other Jurisdictions Could be Undertaken.** Such comparisons could offer valuable insights to drive efficiency improvements, align with best practices, and enhance service quality for consumers. This constitutes an informal kind of international yardstick competition.

- **Alternate Approaches to Stretch Factor Assignments Could be Considered.** Currently, stretch factors are assigned based on inter-utility cost comparisons using the TCB model. A 'Global Stretch Factor' (GSF) could be introduced and set for all utilities. Consideration could be given for setting separate Capital and OMA GSFs. In addition, the GSFs could be augmented with individual utility stretch factors informed by TCB and affecting 'return on equity' (ROE) as either a penalty or a reward. The Board may also consider giving some weight to the rate at which each utility has improved relative to its own past.

- **Quality and Reliability of Service Could Be Incorporated into the Incentive Regulation Formula:** For example, the price-cap model might include a term for quality, (sometimes referred to as a 'q-factor') or a quality term could be incorporated into the stretch factor. Performance Incentive Mechanisms (PIMs) could be incorporated in setting individual ROE's to ensure service quality, reliability and performance.

- **Simulation Modeling Could be Considered:** A small number of ‘artificial utilities’ could be defined with characteristics spanning the range of Ontario distributors that align with the TCB benchmark. Simulation modeling could then be implemented to assess their evolution as government policies and the industry environment change.

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1. Introduction

a. Preface

This project is a collaboration between the Economics Department at the University of Toronto (UofT) and the Ontario Energy Board (OEB). It is being funded by the OEB and Climate Positive Energy at the University. The project is entitled "Review of the Total Cost Benchmarking Methodology for Electricity Distributors". The lead researcher is Adonis Yatchew with research conducted by a team of University of Toronto graduate students including Frederik Dufour, Erik Harris-Uldall, Shuofei Li, Michael Scafe, Leb Jenric Valencia and Lucy Wolff.

This report is the outcome of the first phase of the project which focuses on methodological issues, in particular, the statistical benchmarking approach that the OEB has relied upon for a number of years, evaluation of alternative approaches and benchmarking in other jurisdictions. A literature review is conducted to ensure that the most recent research on statistical benchmarking in incentive regulation contexts informs our analysis. The second phase of this approach will conduct statistical work to evaluate the current approach and alternatives to it.

b. Background and Context

Prior to the restructuring of the Ontario electricity industry, distributor costs were reviewed and approved by Ontario Hydro. Subsequently to industry restructuring in the late 1990s, the OEB was given the responsibility for regulating distributors.[9] In the latter part of the 20th century, Ontario had over 300 distributors of widely varying sizes. Through mergers and acquisitions, this number would eventually decline; at the time of this report there were 56 rate-regulated distributors. It has been argued that even during the period of cost-of-service regulation, an informal version of yardstick competition was in play: "there was a systematic process for comparing performance among distributors. As distributors found better ways to do things, that information would be shared with others, because there was a relatively open public sector system for doing so."[10]

The OEB then moved to implement incentive regulation of distribution companies. The most commonly implemented version linked rate increases (ΔP) to the rate of price inflation (RPI) and productivity gains (X), the so-called 'RPI-X' formulation. At the outset it was agreed that determination of the productivity factor (i.e., the X-factor) would be best determined by

[9] Electricity Act, 1998 S.O. 1998, c. 15 Sched. A. Part X. and Ontario Energy Board Act, 1998 S.O. 1998 c. 15, Sched. B s. 25.35.6, 28, 29, 42.1, 53.16. See also Part IV (Hydro One Inc.)

[10] EB-2007-0673, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008, page 15, fn 6.

data-driven methods. Two general approaches were considered: total factor productivity (TFP)[11] and total cost benchmarking (TCB).[12]

Electricity distribution is capital intensive with long-lived assets. Thus, reliable application of both methods required sufficiently long time series on capital investments. However, the absence of reliable capital data, measured consistently across distributors, led the OEB to consider alternative approaches. In the second generation incentive regulation mechanism, this restricted benchmarking to Operations, Maintenance and Administration (OM&A) costs.[13] However, this approach creates incentives for increased capitalization of costs, thus improving the appearance of OM&A expenditures while potentially distorting the 'repair vs replace decision.'[14] A second approach involved the use of data on distributors from other jurisdictions to estimate productivity growth.

As part of the 2008 Report of the Board for 3rd Generation Incentive Regulation consultations, the Board accepted the Pacific Economics Group (PEG) modeling approach, which relied on U.S. distributor data.[15,16,17] At the same time the Board required that distributors

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[11] TFP goes back to the seminal work of Nobel Prize winner, Robert Solow, and is sometimes known as the Solow Residual. TFP is widely applied at aggregate (i.e., macro) levels and at industry and firm (i.e., micro) levels. The basic idea is that the growth in outputs which cannot be explained by growth in inputs represents growth in productivity.

[12] TCB has its origins in statistical/econometric cost function estimation. The classical Cobb-Douglas production and cost function statistical models, originate in a 1928 paper by C. W. Cobb, and P.H. Douglas entitled "A Theory of Production" published in the American Economic Review. Production and cost functions are duals in the sense that if you know one, the other can be derived using analytic or simulation techniques. This duality is useful in cost and production function estimation because the two share the same set of underlying parameters. This relationship, and its potential use in modeling will be further explored in the second phase of the study, which conducts statistical modeling.

[13] Pacific Economics Group (2008, March 20). Benchmarking the Costs of Ontario Power Distributors. https://www.oeb.ca/documents/cases/EB-2006-0268/PEG_Final_Benchmarking_Report_20080320.pdf.

[14] This approach, with some modifications, has been resurrected in certain jurisdictions.

[15] Ontario Energy Board (2008, July 18). Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. http://www.oeb.ca/oeb/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf.

[16] Ontario Energy Board (2008, September 17). EB-2007-0673, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. http://www.oeb.ca/oeb/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf.

[17] As noted, reliance on external utility data was necessitated by the lack of consistent time-series on Ontario distributor capital data. More recently, a second rationale for relying on out-of-Province data emerged when certain utilities differed sufficiently from the other Ontario utilities to merit statistical comparison with extra-jurisdictional utilities. These were Toronto Hydro-Electricity System Limited (THESL) and Hydro One Inc. Both incorporate data on U.S. utilities in their Custom Incentive Rate (Custom IR) submissions. The use of extra-

assemble capital data in a consistent fashion. This approach led to systematic improvements to calibration of Ontario distributor costs.

Explicitly or implicitly, the Ontario Energy Board has founded its regulatory models (with respect to costs and performance) on some variant of an early paper which proposed yardstick competition based on statistical analysis.[18] Such approaches are only feasible if there is a sufficient number of distributors to allow meaningful statistical analyses.

Since the early years of incentive regulation, data quality, especially with respect to capital variables, has improved steadily along with modifications to cost modeling itself. The assembly, standardization and reconciliation of data as well as modeling was conducted for the Board by the Pacific Economics Group. The work was complicated by ongoing mergers and acquisitions within the distributor industry. The OEB initiated 4th Generation Incentive Regulation consultations in 2010 (EB-2010-0379). By the time of its completion in 2013, the data were of sufficient quality that models were estimated using Ontario distributor data. Overall, both the quality of the data and statistical analyses conducted by the PEG were of high quality. The presence of many utilities (over 70) led to statistically meaningful results.[19] The openness of the process, whereby intervenors could gain access to data and code, facilitated cross-checking, testing and validation of modeling and results.[20] It is difficult to overstate the value of an open vetting process.[21]

c. The Changing Electricity Distribution Landscape[22]

Electricity distribution companies are undergoing a profound transformation driven by at least three major forces: decarbonization, digitization, and decentralization. These in turn have

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jurisdictional data is not unique to Ontario. For example, The Australian Energy Regulator incorporates *Ontario* distributor data in their analyses.

[18] Schleifer, Andrei (1985), "A Theory of Yardstick Competition", Rand Journal of Economics, 16:3 319-327.

[19] In comparison, OFGEM which regulated about a dozen distributors, faced a more difficult statistical challenge because of the relatively small number of distributors.

[20] Nondisclosure and specific use agreements ensured that parties did not use their access for inappropriate purposes.

[21] In academia, replication and testing of results by other parties is a cornerstone of scientific inquiry.

[22] The MIT Energy Initiative report "Utility of the Future" (2016), provides an insightful overview of evolving electricity industries. This comprehensive and lengthy document is succinctly summarized by Pérez-Arriaga, Jenkins, and Batlle (2017). Building on this foundation, Burger, Jenkins, Batlle, and Pérez-Arriaga (2019) offer valuable insights into the growing complexity of distribution systems. Makholm, J. D. (2018) presents arguments about how the changing functions and roles of distributors are complicating incentive regulation. Additionally, Costello (2012) delves into the regulatory challenges stemming from technological advancements in the industry.

led to increased democratization of energy systems.[23] These changes are reshaping the dynamics of electricity provision and consumption, influenced by advancements in distribution-side technologies. The increasing adoption of distributed generation, flexible demand response systems, energy storage solutions, and sophisticated power electronics is revolutionizing how electricity services are delivered and used. Additionally, the rapid decrease in costs of certain technologies (e.g., wind, solar and storage) and the widespread integration of information and communication technologies are enabling more efficient and flexible electricity consumption. These technologies, subject to privacy issues, can also enhance visibility into network utilization and enable better control over power systems. The transition is marked by a shift towards more decentralized and user-responsive electricity services, representing a significant evolution in the energy sector towards accelerating innovation and potentially efficiency.

Thus, the roles and responsibilities of electricity distribution companies are evolving in response to technological advancements, policy changes, regulatory updates, and shifting consumer demands. While traditionally focused on delivering electricity from the grid to consumers, these companies are now facing a more complex and multifaceted environment which we detail further below.

d. What Can We Learn from Transitions in Other Industries?

Tectonic shifts in telecommunications technologies began in the 1980s with the separation of local loop and long-distance services. This was followed by game-changing innovations in mobile communications. These changes transformed the nature of telecom regulation, which continues to evolve.

We can expect the transformation of energy systems to have a profound impact on electricity regulation. From the perspective of cost benchmarking, one needs to ask to what degree are past data informative of future costs. Should greater weight be placed on more recent data?

Cost benchmarking focuses on ‘static efficiency’, i.e., cost minimization based on incumbent technologies, with attention to *incremental* productivity growth. But it is ‘dynamic efficiency’ that is arguably of greater importance, because it entails a framework which promotes

[23] The decline in ‘minimum efficient scale’ underlies the proliferation of distributed energy resources, which are enabling local energy networks and giving communities more control over their energy supply. See, e.g., Yatchew, A. 2019, “How Scalability is Transforming Energy Industries” Energy Regulation Quarterly, 7:2, 35-44. The decarbonization imperative has led to numerous consultations and policy debates.

innovation. The changes that are occurring could lead to tipping points, with the potential for impaired or stranded assets.[24]

From a regulatory standpoint, one of the challenges is that innovation does not necessarily lead to immediate reductions in costs. In hydrocarbon industries, horizontal drilling and hydraulic fracturing comprised a game-changing combination we call fracking. It revolutionized North American natural gas markets (beginning in 2008) and global oil markets (in 2014). Yet, it took many years of investment and development before it bore fruit.

For electricity distribution, direct market discipline will likely come from decentralization of energy production, reducing dependence on wires (as well as on conventional centralized generation). Minimum efficient scale in generation continues to drop dramatically, leading to the emergence of competitive pressures on incumbent generators and even on distributors.[25] To the extent that electricity services become increasingly decentralized, the underlying regulatory model will need to be revisited. In most jurisdictions, lowest demand is in the early morning hours and peak consumption is in the daytime and evening.[26] The rapid expansion of solar generation in California has led to an inversion of system demand as self-generation reduces the need for conventional supply during the daytime, followed by rapidly increasing demand as the sun sets. The resulting so-called 'duck curve' provides a prominent example of such competitive pressure.[27]

Much attention has been paid to the decarbonization initiatives that have been undertaken in Ontario and in many parts of the world. This report devotes some thought to the evolving nature of distributors in an energy transition. Yet, the collective response has, arguably, been weak. At the time of the first UN Conference of Parties (COP 1) meeting in 1995, the hydrocarbon share of energy was 80%. Three decades later, and after close to 30 COP meetings, that share remains unchanged. We have been unsuccessful in implementing policies which

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[24] In some jurisdictions, efforts are made to benchmark utility innovation and to incorporate this into the regulatory process.

[25] The origins of economic regulation at the beginning of the 20th century lie in the need to control market power. In electricity industries, the essentiality of the service provided a second powerful rationale for regulatory intervention.

[26] For example, this is the case in Ontario, https://www.ieso.ca/power-data.

[27] See, for example, "What the duck curve tells us about managing a green grid", California ISO, 2016, https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf. More recently, the 'belly' of the duck is getting deeper: "As solar capacity grows, duck curves are getting deeper in California", U.S. Energy Information Administration, June 21, 2023, https://www.eia.gov/todayinenergy/detail.php?id=56880, leading some to now call it the 'canyon curve': "EPRI Head: Duck Curve Now Looks Like a Canyon". *Power,* Sonal Patel, April 27, 2023, https://www.powermag.com/epri-head-duck-curve-now-looks-like-a-canyon/.

move the needle globally.[28] Climate change has been a 'slow-burn' threat to which, arguably, the response has been haphazard. Democracies tend to respond much more effectively to existential threats.[29] If a turning point is reached on the climate front, we can expect major changes in distributor priorities and agendas, as well as the directions and decisions set by regulators. In the meantime, an important objective for the OEB is to benchmark and incentivize innovation.

[28] Nobel Prize Winner William Nordhaus argues that this is due to the absence of efficacious policies and ineffective incentives. Nordhaus, W. (2020). "The climate club". Foreign Affairs, 99(3), 10-17.

[29] The response to Covid-19 provides a powerful example where corporations, policy makers and regulators fast-tracked approvals and production of vaccines and anti-virals.

2. Background

a. Context

For much of the 20th century, natural monopolies in energy were regulated using cost-of-service regulation.[30] This approach entailed considerable and recurring administrative costs for regulators and for companies. It was well understood that regulation suffered from asymmetry of information between the former and the latter. The 1980s saw the first application of incentive / performance-based regulation to the telecom industry.[31] The most common form of incentive regulation uses a price-cap formula:

$$P_1 = P_0 \times (1 + RPI - X + Z)$$

where

- P_0 is the initial rate approved by the regulator
- RPI is the rate of price inflation
- X is the productivity factor
- Z represents factors outside company control
- P_1 is the rate in the subsequent period.

The underlying theory argued that price-caps, updated annually for the rate of inflation, would increase incentives for efficiency *and* for information revelation. Nevertheless, regulators faced the challenges of calibrating initial allowable costs and therefore initial rates P_0, and in assigning a suitable productivity factor X.

In settings where there are multiple regulated entities, regulators can reduce their informational deficiencies by employing 'yardstick competition,' which uses comparative benchmarks in setting allowable prices or rates. According to Shleifer,[32] when dealing with

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[30] Rate-of-return regulation can be seen as a variant of cost-of-service regulation where greater attention is devoted specifically to reasonable rate of return on investment. The concept of 'benchmarking' has long been an accepted part of utility regulation. For example, techniques from finance such as the 'capital asset pricing model' (CAPM) have long been used to determine appropriate rates of return derived from risk-return data.

[31] Incentive regulation is an outgrowth of tectonic shifts in views on the role of government. The Great Depression undermined faith in markets – their inability to restore employment in labour markets was seen as a monumental *market failure*. From the 1930s to the 1970s western democracies experienced an increasing role for government through legislation, nationalization and regulation. However, the stagflation of the 1970s was seen as a *government failure*, contributing to a reversal of this trend. By the late 1970s, the view that the role of government had become too large, gained momentum. This led to economic liberalization, deregulation and privatization. The catchphrase became 'Competition where possible, regulation where necessary.' Economic theorists, policymakers and regulators sought mechanisms to introduce better incentives into regulatory processes. See, e.g., A. Yatchew, (2014), "Economics of energy, big ideas for the non-economist", Energy Research & Social Science, 1, 74-82.

[32] Schleifer, Andrei (1985), "A Theory of Yardstick Competition," Rand Journal of Economics, 16:3 319-327.

multiple similar, non-competing entities (for example, electricity distribution companies), setting a firm's price based on the expenses of *other* firms should constitute an effective regulatory strategy. This approach leaves individual firms without direct control over their approved prices or tariffs, which are instead determined by the costs of other firms. Consequently, each firm effectively operates under a fixed price contract, ensuring budgetary balance as prices should not drop below efficient costs if firms are alike. Ideally, this method prompts each firm to essentially compete with others, achieving an equilibrium price that covers all efficient costs as though there was direct competition.

However, finding identical firms to implement the method is challenging. This is where statistical techniques such as cost function regression come into play. The essential objective is to adjust for differences in firm characteristics and business conditions, allowing for the creation of standardized benchmark costs.[33] Adjusted costs can be used in a yardstick framework, helping regulators to reduce their informational disadvantage and apply effective incentive mechanisms reducing the risk of excessive rents. Nonetheless, the availability and quality of data for such benchmarking are often uncertain. Additionally, using different benchmarking techniques and failing to combine cost and quality factors can result in inaccurate conclusions.[34]

Ontario is well-suited to a statistical approach because there are multiple distribution companies across the province, even though there is wide variation in size and operating conditions. Hydro One originally served the role of “default distributor” given its large service territory area, encompassing areas beyond all other distributor boundaries. To our knowledge, the first peer-reviewed cost function modeling of Ontario electricity distributors is in Yatchew (2000). That analysis used data on 74 Ontario companies. Yatchew (2001) then recommended using the cost function analysis to implement incentive regulation via yardstick competition. Over the subsequent two decades, the OEB relied upon increasingly more intricate cost function modeling and robust data collection to inform its price-cap parameters. That work has been conducted by PEG.

In addition to cost function estimation, the OEB has also relied to a lesser degree on modeling productivity growth using ‘Total Factor Productivity’ (TFP) approaches. Most recently, the OEB has also considered the modeling and comparison of costs for specific activities, known as ‘Activity and Program-Based Benchmarking’ (APB) such as billing, vegetation management and line maintenance.

[33] Jamasb and Pollitt (2001, 2003), as well as Estache, Rossi, and Ruzzier (2004), provide comparative discussions of these methods.

[34] See, for example, Giannakis, Jamasb, and Pollitt (2004, 2005).

b. Incentive Regulation

There are numerous studies that analyze incentive regulation. As electricity industries undergo change, innovation in all segments including distribution is essential. Dynamic efficiency refers to the ability of firms to continuously adapt, innovate, and improve resource allocation over time. It goes beyond static efficiency, which focuses on maximizing efficiency at a given point in time with existing technology. Dynamic efficiency is driven by investments in research and development which create the potential for future productivity gains. It takes a long-term view of efficiency. Dynamic efficiency can be enhanced by government policies and regulatory initiatives that encourage or even subsidize research and development. Electricity utilities tend to be risk averse and so investments with uncertain outcomes are often avoided. There are also short-term pressures such as stakeholders who prioritize immediate gains over long-term investments.[35,36]

A recent paper by Joskow (2024) reviews the gradual expansion of incentive regulation into U.S. distribution (and transmission) systems. Joskow also identifies various modes of implementation and how these can be improved. The paper by von Bebenburg, Brunekreeft and Burger (2023) revisits capex bias issues that date back to the classic paper by Averch and Johnson (1962). Brunekreeft (2023) suggests regulatory incentives which can enhance grid

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[35] Firms generally do not engage in socially optimal levels of R&D investment to the extent that there are spill-over effects that cannot be monetized internally. A classic example is Newcomen's 1713 invention of a steam engine which had the narrow purpose of pumping water out of coal mines. Newcomen could not have anticipated that the 'spillover' effects of his invention would be the Industrial Revolution itself.

[36] Distribution industry investment in R&D focuses on several key areas. Grid modernization is crucial to handle the changing mix of energy sources, including renewables and electric vehicles. R&D helps develop smarter and more resilient grids with advanced metering, sensors, and automation. Additionally, reducing energy losses and optimizing usage are top priorities. This translates to R&D efforts in better energy storage solutions and demand management programs.

Keeping the lights on is a core function. Technologies like self-healing grids, advanced fault detection, and distributed generation systems are developed to prevent outages and ensure swift recovery. Cybersecurity is another critical area, and R&D focuses on advanced encryption, detection systems, and secure communication protocols to safeguard the grid infrastructure. R&D also aims to improve customer experience through smart home technologies, personalized energy data, and innovative billing programs.

However, much of the expenditure on innovation does not come from within distribution companies. Collaborations with universities, research institutions and government agencies provide revenue streams. Industry consortiums such as the Electric Power Research Institute (EPRI) pool resources for large-scale projects. Government support also plays a role, with grants and incentives encouraging R&D in clean energy and efficiency. In Ontario, an especially prominent example of collaboration across multiple entities is the Grid Modernization Centre proposed by Climate Positive Energy at the University of Toronto.

Compared to some industries, the percentage of revenue dedicated to R&D by electricity distribution companies might still be on the lower side. Additionally, the regulatory environment can influence these investments, depending on how costs are treated and whether incentives for innovation are in place.

reinforcement. Kuosmanen and Johnson (2021) examine peer-group methods for benchmarking.[37]

Poudineh and Mirnezami (2020) discuss regulatory mechanisms which allow companies to undertake risks without excessive penalties. This is mentioned earlier in the executive summary and in the preceding section. Lowry, Deason and Makos (2017) look at multi-year rate plans in the U.S. Joskow (2014) reviews incentive regulation in electricity distribution which builds further on his earlier paper Joskow (2008). Shuttleworth (2005) discusses the practical aspects of using benchmarking in incentive regulation.

Yatchew (2001) discusses yardstick competition with an application to Ontario distributors. As mentioned earlier, Schleifer (1985) provides an early analysis of the use of regression techniques for benchmarking natural monopolies.

c. Evolving Roles of Electricity Distributors

The roles and responsibilities of distributors continue to change in response to decarbonization, digitization and decentralization (the ‘three d’s’).[38] The electricity sector is witnessing pivotal changes in service provision and consumption, influenced by advancements on the distribution side of power systems. The emergence and proliferation of technologies such as distributed generation, flexible demand response, energy storage, and sophisticated power electronics and control devices are revolutionizing the ways in which electricity services are provided and consumed. Concurrently, the rapid reduction in costs and the widespread adoption of information and communication technologies are facilitating more efficient and flexible electricity usage. These technologies can also improve the visibility of how networks are utilized and allow for better control over power systems. The transition is characterized by a move towards more decentralized and user-responsive electricity services, highlighting a significant shift in the energy landscape towards innovation and efficiency.

The roles of electricity distribution companies are evolving due to advancements in technology, policy priorities, regulatory changes, and shifts in consumer expectations. Traditionally, these companies were responsible for the task of distributing electricity from the grid to consumers. However, their role is now expanding and becoming more complex for several reasons:

- Integration of Distributed Energy Resources (DERs): The emergence of DERs, such as solar panels, wind turbines, and energy storage systems is transforming distribution companies into active managers of bi-directional energy flows. They must manage local generation and injection of supply into the distribution grid, accommodate

[37] Detailed summaries of these and other papers are contained in Appendix C to this Report.

[38] The Council of European Energy Regulators (CEER) has now renamed the ‘three d’s’ as digitization, decarbonization and dynamic regulation. The latter is to seek “European solutions for adaptive regulation in a fast-changing world”, https://www.ceer.eu/dynamic-regulation.

prosumers[39] (consumers + producers), and adapt to changing patterns of electricity demand.[40] As efforts to decarbonize the energy sector intensify, distribution companies play a crucial role in integrating renewable energy sources, contributing to the reduction of greenhouse gas emissions and promoting sustainability.

- Digitization and Smart Grids: The adoption of smart grid technologies and digital tools requires distribution companies to handle vast amounts of data, improve network efficiency, and enhance reliability and customer service through real-time monitoring and control. As the first generation of 'smart meters' approach the end of their useful lifetimes, utilities must now position themselves to install the next generation which incorporates new functionalities, potentially setting the stage for dynamic demand response.

- Shared Infrastructure and Grid Modernization: Increasing interdependence between distributors, driven by shared services such as control rooms and cloud computing can create their own benchmarking challenges as distributors become cointegrated.

- Electrification of Transportation: The growing adoption of electric vehicles (EVs) and the installation of charging infrastructure will increase electricity demand and require upgrades to the distribution infrastructure to handle peak loads during high charging periods. This can strain existing distribution infrastructure and may require upgrades to handle the increased load. The demand for electricity from EV charging stations can be unpredictable and vary significantly by location and time, complicating demand forecasting and grid management.

- Electrification of Heating: Growing momentum to shift from natural gas heating to heat pumps will increase electricity demand during cold months, but potentially reduce demand during hot months due to the increased efficiency relative to conventional air conditioning.

- Regulatory, Policy and Market Changes: Changes in regulation, policy imperatives, and the structure of electricity markets are pushing distribution companies to innovate in how they operate, maintain, and invest in the grid. They must adapt to new regulatory frameworks that encourage competition, efficiency, and innovation. Regulatory levers constitute an important channel for incentivizing innovation.

- Security and Cyberthreats: Energy systems are at increasing risk of cyber-attacks. Distributors are on the front-line of delivery of key services and protection of system operating information, control systems and customer data is essential. The

[39] The term is attributed to futurist Alvin Toffler.

[40] See earlier discussion of the Duck Curve.

interconnectedness of global networks creates opportunities for hackers operating from anywhere in the world.[41] Protecting energy systems from cyber threats is becoming a leading priority, given the interconnected nature of global information networks and the critical role of distribution companies in delivering essential services.

- Customer Engagement and Services: The evolution of consumer preferences towards more sustainable and reliable energy solutions means distribution companies must offer more advanced and flexible services, including demand response programs, energy management, and customized energy solutions.

In addition to these evolving roles, electricity distribution industries have encountered multiple challenges, including:

- Infrastructure Refurbishment: Significant investment in distribution infrastructure has been necessary due to the need for replacement, expansion, and upgrades. This ongoing investment is crucial to minimize long-term costs and ensure reliability, especially as many existing assets are nearing the end of their useful lifespan. The replacement of aging assets at current prices contributes to upward pressure on rates, along with increased operational, maintenance, and asset management costs.

- New and Emerging Technologies: The Ontario distribution sector has been adopting new technologies such as smart meters and smart grid devices. While these innovations offer benefits, they also come with increased costs, contributing to the overall cost pressures faced by distributors.

- Conservation and Demand Management (CDM): Distributors must meet CDM targets set by the IESO. To achieve these objectives, distributors have relied on province-wide programs, with some larger distributors proposing additional programs to enhance conservation and demand management efforts.

- Regulation and Government Policy: Increased government involvement, through legislation, policy, and directives, adds to the uncertainty and complexity of the regulatory environment for distributors.

- Resiliency: Distributors continue to face risks from unexpected weather events and other factors that could lead to loss of power. The OEB has recently launched new initiatives to improve the resiliency of the electricity sector, driven by climate change and increasing extreme weather events. Key initiatives include the Vulnerability Assessment and System Hardening Project (VASH), which aims to help distributors incorporate climate resiliency

[41] See e.g., McMillan, R., Hobbs, T., & Volz, D. (2021, May 11). "Beyond colonial pipeline, ransomware cyberattacks are a growing threat schools, hospitals, companies are targeted by 'cyber weapons of mass destruction.'" Wall Street Journal. Ransomware is a leading motivation for hackers.

into their planning and operations. The project focuses on several objectives, including developing a standardized methodology for vulnerability assessments, cost-benefit analysis of system hardening investments, and a "value of lost load" (VoLL) model to quantify customer impact during outages. The OEB is also engaging stakeholders to explore these approaches, with an emphasis on ensuring that system enhancements prioritize customer value.[42]

An excellent overview of evolving electricity industries is contained in the MIT Energy Initiative report Utility of the Future (2016). This lengthy document is succinctly summarized by Pérez-Arriaga, Jenkins and Batlle (2017). Two valuable related papers by Burger, Jenkins, Batlle and Pérez-Arriaga (2019) further elaborate on the increasing complexity of distribution systems. Makholm, J. D. (2018) argues that the evolution of distributor functions and roles complicates incentive regulation. Costello (2012) also addresses these regulatory challenges arising out of technological change.

d. Benchmarking Efficiency and Productivity

The central focus of this report is a review of the OEB econometric Total Cost Benchmarking methodology for electricity distributors which primarily relies upon cost function estimation. The main approaches that we consider and evaluate are:

- Total Cost Benchmarking (TCB) using econometric cost modeling,
- Total Factor Productivity (TFP) indices,
- Data Envelopment Analysis (DEA), and
- Stochastic Frontier Analysis (SFA).

These methods exhibit distinct differences. For instance, some are parametric, i.e., they require that the analyst specify the functional form. Others do not have such requirements, they are 'non-parametric'. Certain methods can account for noise in the data, while others cannot. Only some of the methods are capable of measuring both technical and allocative efficiency.[43] While some methods are suited for time series data, others are not.

[42] See Engage With Us: Distribution Sector Resilience, Responsiveness & Cost Efficiency

[43] Technical efficiency refers to the use of minimum quantities of inputs to produce a given level of output, or conversely, maximizing output given specific quantities of inputs. Allocative efficiency refers to the selection of optimal combinations of inputs (such as labour and capital) to produce a specified amount of output at the lowest possible cost, given the prevailing prices of those inputs.

Properties of Benchmarking Methodologies[44]				
	TCB	TFP	DEA	SFA
Parametric	Yes[45]	No	No	Yes
Allows for random error (noise) in data	Yes	No	No	Yes
Statistical testing	Yes	No	No	Yes
Can measure				
Scale Economies	Yes	No	Yes	Yes
Technical Change	Yes	No	Yes	Yes
Can incorporate differences in business conditions	Yes	No	No[46]	Yes

TCB is a sophisticated approach that employs econometric analysis to compare an organization's total costs against those of other firms. This method utilizes statistical models to analyze the relationship between total costs and various influencing factors, such as scale of operations, input prices, and business conditions across different organizations. By integrating econometric techniques, this benchmarking approach allows for a more nuanced understanding of cost drivers and efficiencies. It adjusts for differences in company size, output levels, and other variables that affect costs, providing a clearer comparison of inherent cost efficiencies or inefficiencies among firms. These adjustments make it possible to identify specific areas where an organization can reduce costs or improve processes relative to its peers. TCB can offer insights into how different factors contribute to cost variations and highlights opportunities for optimization. The method is especially useful in sectors with complex operations and significant cost differentials, as is the case for electricity distribution companies. It is amenable to rigorous statistical testing of hypotheses, such as whether one or another business condition has a material impact on costs. These models require extensive data, preferably for a sufficient number of firms to permit statistical estimation. The estimation methods are complex and can be sensitive to the modeling assumptions.

TFP approaches are simpler to implement, and do not impose the same data requirements as econometric TCB. They are useful for evaluating the efficiency and productivity of firms by considering all inputs used in the production process. Unlike partial productivity measures, which look at the output relative to a single input (e.g., labour or capital productivity), TFP accounts for the combined effect of multiple inputs, including labour, capital, materials, and energy, to produce output. TFP modeling aims to capture the portion of output

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[44] See, e.g., Coelli, Rao, O'Donnell and Battese (2005). An Introduction to Efficiency and Productivity Analysis. Springer Science & Business Media. Second Edition. Chapter 12, Table 21.1, page 312, provides a similar summary.

[45] TCB can be readily modified to allow nonparametric and semiparametric specifications. Technical details are in subsequent portions of this report.

[46] In principle, allowing for business conditions can be accomplished by selecting subsets of utilities with similar characteristics.

growth that cannot be directly attributed to the quantity of inputs used, effectively measuring the improvements in the production process or technological advancements. The basic premise behind TFP is that increases in output are not only the result of more inputs but also of more efficient use of these inputs. An aggregate measure of output is obtained by calculating a weighted combination of three outputs: number of customers served, system capacity peak demand and retail deliveries. Efficiency could stem from better management practices, technological innovations, economies of scale, or improved worker skills. TFP is calculated by dividing the total output of a company or economy by the weighted average of inputs. If the ratio increases over time, it indicates that the entity is producing more output per unit of input, signaling improved overall productivity and efficiency. However, TFP does not allow for the incorporation of business conditions, noise in the data, or statistical testing. TFP does require accurate and consistent data on prices and quantities of inputs and outputs. It cannot distinguish between scale effects, and technical or allocative efficiency.

DEA is a non-parametric and non-statistical approach to assessing efficiency.[47] Unlike parametric methods, which assume a specific functional form for the production function, DEA constructs an empirical production frontier to identify efficient firms against which others are compared. This is done by measuring the ratio of weighted outputs to weighted inputs for each unit, without requiring a predetermined relationship between inputs and outputs. Typically, an efficiency score is assigned to each firm based on its relative performance, with a score of 1 (or 100%) indicating an efficient unit that operates on the frontier. Scores less than 1 indicate inefficiency, where improvements in input use could lead to better performance. DEA helps in identifying best practices, setting targets, and suggesting improvements for inefficient distributors. In its simplest form, the approach does not permit incorporation of business conditions or noise in the data.

SFA is a statistical method used to estimate the efficiency of firms in producing outputs from a set of inputs. Unlike DEA, which is non-parametric, SFA is a parametric approach that assumes a specific functional form for the cost function, and importantly, for the noise or statistical error in the data. SFA separates inefficiency effects from random noise in the data, attributing deviations from the frontier to these two sources distinctly. Efficiency is measured by the distance of an entity from this frontier, with those on the frontier considered efficient. SFA models incorporate a two-part error term: one part captures random shocks and measurement errors (noise), which can affect the output level but are beyond the control of the firm; the other part captures inefficiency, reflecting the shortfall in output due to factors that can be controlled. The approach permits incorporation of business conditions. However, its most important limitations are sensitivity to outliers and to the specific functional form (i.e., the probability distribution) selected for the inefficiency component in the residual. Estimation

[47] See Appendix D Glossary of Technical Terms for a brief explanation of the distinction between parametric and nonparametric modeling.

using various approaches (TCB, SFA and others) comprises a beneficial step in arriving at robust conclusions.[48]

e. Benchmarking in Other Jurisdictions

Appendix A to this report provides a detailed survey of benchmarking productivity and reliability and their relation to the regulatory regime in various European countries, Australia, the USA and certain Canadian Provinces. Here we provide an overview of the survey.

i. Benchmarking Productivity

In Germany, the Bundesnetzagentur employs revenue caps and efficiency benchmarking through Data Envelopment Analysis and Stochastic Frontier Analysis. France's Commission de Régulation de l'Énergie sets distribution tariffs and benchmarks efficiency through comparisons with other European network managers, using methods including DEA and SFA. In Great Britain's, OFGEM's RIIO model emphasizes Revenue, Incentives, Innovation, and Outputs, with a focus on long-term investment and consumer outcomes. In Denmark, the Danish Utility Regulator (DUR) regulates electricity distributors using a revenue cap model with efficiency targets and adjustments based on service quality.

The Netherlands' Authority for Consumers and Markets uses an X-factor, which is adjusted based on detailed analysis and forecasting of cost trends and efficiency improvements. Norway's NVE-RME applies a revenue cap system that includes an efficiency assessment using Data Envelopment Analysis, focusing on service quality to prevent cost-cutting that could impact infrastructure and service. Sweden's Energy Markets Inspectorate has shifted to ex-ante revenue caps with a focus on Total Expenditure (TOTEX), using DEA for efficiency benchmarking and incorporating metrics like interruption time and frequency.

In Spain, electricity distribution is regulated by the Comisión Nacional de los Mercados y la Competencia (CNMC). Since the jurisdictional change in 2019 under Royal Decree Law 1/2019, the CNMC has the authority to set revenues and tariffs from 2020 onwards. The Spanish market is characterized by a mix of five large and 328 small distribution system operators (DSOs), with the large ones holding about 90% of system revenues. The regulatory cycle, renewed every six years, involves a comprehensive approach to determine the revenue cap for DSOs, including components such as Capital Expenditures (CAPEX), Operations & Management Expenditures (OPEX), and incentives/penalties based on performance. The Regulatory Asset Base (RAB) is adjusted annually, incorporating new investments and depreciation. The Weighted Average Cost of Capital (WACC) method, using the Capital Asset Pricing Model (CAPM), determines the Rate

[48] Regression techniques, such as Total Cost Benchmarking are also sensitive to outliers because extreme observations can have a material impact on the estimate of the regression function, i.e., the conditional mean function. A remedy is to estimate the conditional median function or more generally quantile regression. See, e.g., Yatchew, A. 2001: "Incentive Regulation of Distributing Utilities Using Yardstick Competition", Electricity Journal, Jan/Feb, 56-60.

of Return (RoR). Spain's CNMC also includes operational maintenance allowances and incentives for extending the regulatory life of assets, alongside remuneration for various regulated tasks based on a set of reference values and performance against an efficient company.

Italy's energy infrastructure is regulated by the Regulatory Authority for Energy, Networks, and Environment (ARERA), which oversees about 126 DSOs. Since the energy sector liberalization in 2007, an incentive-based regulation system has been in place to enhance efficiency. The system combines input-based incentives focusing on productivity with output-based incentives aimed at ensuring service quality. Italy's regulatory framework involves a price cap mechanism that mandates annual reductions in operational expenditures by an efficiency factor 'X'. Service quality incentives focus on continuity of supply, measured by the System Average Interruption Duration Index (SAIDI), with performance targets adjusted geographically based on population density.

The Australian Energy Regulator (AER) is responsible for ensuring that electricity distribution services are reliable and affordable. It conducts annual benchmarking exercises across 13 electricity distributors, analyzing data such as operating expenses, capital investments, network reliability, and customer satisfaction. This helps identify inefficiencies and set performance standards. The AER uses methods like total factor productivity and econometric models to evaluate utilities, setting efficiency targets that encourage utilities to improve operations. Ontario distributor data have been used by the AER in its benchmarking exercise. The overall AER process also fosters innovation, with incentives for adopting technologies that enhance efficiency and service quality.

Performance-Based Regulation (PBR) in the US has evolved, especially post-2015, to address the challenges of integrating renewable energy, enhancing grids, and developing infrastructure for electric vehicles. PBR aims to incentivize utilities to improve efficiency beyond traditional cost recovery models. The approach may include multiple elements such as Performance Incentive Mechanisms (PIMs), revenue decoupling[49] and Multi-Year Rate Plans (MYRPs), which are adjusted based on various external indices to encourage cost efficiency and service quality. Some state regulators include specific initiatives encouraging utilities to adopt new technologies and practices aligned with policy goals like decarbonization and grid modernization. Examples include New York's Reforming Energy Vision (REV) and California's programs for utilizing electric vehicle batteries as power sources. Hawaii's recent PBR plan exemplifies comprehensive regulation, aiming to generate all electricity from renewable sources by 2045, with mechanisms in place to adjust revenues and incentivize performance.

[49] Revenue decoupling is a regulatory mechanism that separates a utility's revenue from the volume of energy it sells. Traditionally, utilities earn more by selling more energy, but decoupling breaks this link to encourage energy efficiency. With decoupling, utilities are allowed to recover a fixed amount of revenue, regardless of energy sales. If energy sales fall due to efficiency programs or other factors, rates may be adjusted to meet revenue targets. This ensures that utilities remain financially stable while supporting energy conservation and efficiency initiatives without losing income.

Since 2012, Alberta has adopted a PBR approach, using an I-X (inflation minus productivity) structure for electricity and gas distributors. The current plan for 2024-2028 introduces significant changes, including adjustments to the calculation of the I factor and the use of forecasted rather than lagged data. There is a focus on Total Factor Productivity (TFP) growth studies, despite skepticism from some distributors about their reliability. The Alberta Utilities Commission (AUC) continues to support the use of TFP growth studies, combined with a stretch factor and an X factor, to determine adjustments in rates. The PBR framework in Alberta includes an earnings-sharing mechanism where utilities share incremental earnings with customers based on specified thresholds of return on equity (ROE). The plan also incorporates supplemental capital funding mechanisms to encourage prudent management of capital costs.

The regulatory landscape in British Columbia is overseen by the British Columbia Utilities Commission (BCUC), which regulates both the electricity and natural gas sectors. The largest electricity provider, BC Hydro, serves 95% of residents, with FortisBC serving most of the remaining population. A comprehensive review of electricity regulation started in 2019, with ongoing considerations for adopting new incentive-based regulation. BCUC currently utilizes a Demand Side Management program, Service Plans for tracking performance, and traditional cost-of-service regulations that align rates directly with costs. There are discussions about introducing new regulatory measures, including 3-year test periods for rate regulations and enhanced benchmarking practices, though details remain under negotiation and are not publicly disclosed.

ii. Benchmarking Reliability

There are two main reasons for discussing benchmarking of service quality and reliability in this study, the main focus of which is benchmarking costs.

The first reason is to advance the possibility of enhancing comparative cost analyses by including metrics such as outage frequency and duration. It may be possible to do so within TCB models. The second reason is that performance statistics could be incorporated within the Incentive Regulation Mechanism (IRM) to incentivize improved service performance. For example, the price-cap model might include a term for quality, sometimes referred to as a "q-factor," or it could be incorporated into the stretch factor.[50] CAIDI, SAIDI, and SAIFI are examples of commonly used reliability metrics which could also be included in the TCB model.

Internationally, there is a trend towards linking reliability standards and incentives to the Value of Lost Load (VoLL). This connection involves penalties for failing to meet reliability targets, thereby holding distributors accountable and encouraging them to maintain a stable grid.

[50] The Ontario Energy Board (OEB) requires utilities to report on average power interruptions per customer and the duration of these interruptions. These statistics are available in public scorecards and summaries but have not yet been used in total cost or activity-based benchmarking.

The Council of European Energy Regulators (CEER) and the Energy Community Regulatory Board (ECRB) publish benchmarking reports on the quality of electricity and gas supply. Regulatory incentive regimes in Europe often include rewards for superior performance and penalties for inferior performance, primarily focusing on continuity of service at the distribution level. Some countries automatically compensate customers for service interruptions that exceed certain thresholds. Notably, many countries have reported improved supply continuity following the implementation of incentive or compensation schemes.

In the Netherlands, the regulatory authority incorporates a quality incentive (q-factor) into its revenue cap framework, rewarding or penalizing distributors based on their performance relative to outage duration or frequency. In Sweden, service interruptions are benchmarked using indicators like average interruption time (AIT) and frequency (AIF). Regulatory adjustments are made based on comparisons with historical norms, and compensatory measures are mandated for customers enduring prolonged outages.

In the United Kingdom, reliability targets are established with associated rewards and penalties. The incentive rate reflects customer willingness to pay for reliability improvements, typically based on VoLL. Under current regulations, the maximum incentive revenue or penalty for distributors is capped to prevent excessive burdens on customers.

The Australian Energy Regulator (AER) sets performance targets to minimize customer electricity interruptions and monitors outcomes. Financial rewards or penalties are assigned based on distributor performance relative to these benchmarks. The Service Target Performance Incentive Scheme (STPIS) applies financial incentives or penalties based on a 5-year average of service reliability, viewing customer outages as a 'negative output' in productivity analyses.

The OEB is presently engaged in a VASH Project, which in response to a letter of direction from the Minister of Energy is standardizing a methodology for risk-based vulnerability assessments and developing a VoLL to be incorporated into filing requirements for distributors.

Overall, integrating reliability into regulatory frameworks and cost benchmarking is seen as a vital strategy for enhancing service quality in electricity distribution which incentivizes cost minimization. Different jurisdictions employ various mechanisms to incentivize improvements and ensure accountability.

f. Literature Review

Appendix E to this report contains a literature review, with an annotated bibliography of selected papers and an extensive reference list. The review is organized along several themes: evolving roles of electricity distributors, incentive regulation, benchmarking efficiency and productivity, and some additional themes which include quality of service, network security, alternate approaches to benchmarking, investment timing and studies from other industries. The literature review leads us towards several preliminary observations.

Challenges of Benchmarking in a Changing Regulatory Landscape: The traditional approach to benchmarking and incentive regulation is facing new complexities due to evolving roles and responsibilities within the energy sector. Utilities are no longer solely focused on basic service delivery; they may be responsible for grid modernization, integration of renewable energy sources, and cybersecurity measures. These changing priorities make it difficult to establish clear benchmarks and incentivize the right behaviours. For example, a focus on pure cost reduction might not capture investments in grid resilience, which can be crucial for long-term reliability.

The Need for Innovation and Dynamic Efficiency: Static efficiency, which focuses on maximizing efficiency at a given point, is no longer enough. With the rapidly changing energy landscape, the ability to adapt and innovate – "dynamic efficiency" – is becoming increasingly critical. However, there's a lack of consensus on how to integrate incentives for innovation into the regulatory framework. How can we measure and reward utilities that invest in cutting-edge technologies or develop new business models for a more sustainable future? Striking the right balance between rewarding innovation and ensuring affordability for consumers remains a challenge.

Quality Matters, Integrating Quality Standards into Benchmarking: Benchmarking often focuses primarily on cost and efficiency. However, quality of service should also be a key consideration. Including metrics for customer satisfaction, reliability, and outage response times into benchmarking frameworks can incentivize utilities to prioritize service excellence alongside cost control.

Results of Productivity and Incentive Regulation: Early studies indicate positive impacts of incentive regulation on productivity. Some studies, using more recent data, suggest a slowdown in measured productivity growth. This might be due to the difficulty of accurately capturing the effects of changing roles and responsibilities within the industry. Traditional benchmarks might not reflect the additional complexities utilities are now facing.

Network Security, A New Frontier for Benchmarking: Network security is paramount in today's digital world. Cybersecurity threats and physical infrastructure vulnerabilities pose serious risks. Developing effective metrics for benchmarking network security and including them in regulatory frameworks is essential. This will incentivize utilities to invest in cybersecurity measures and ensure the resilience of the grid.

Benchmarking Methodologies, No One-Size-Fits-All: There's no single "best" method for benchmarking. The most effective approach depends heavily on the availability of relevant data, particularly detailed information about capital investments. Furthermore, the presence of multiple comparable utilities within a region greatly facilitates calibration of suitable benchmarks. This allows for a more nuanced comparison and avoids penalizing utilities operating in inherently different circumstances.

3. Methodologies for Assessing Costs and Productivity

This section provides a more technical and detailed description of methodologies and approaches to productivity and cost analysis. In addition to the four main approaches described in the previous section – TCB, TFP, DEA and SFA – included here is an overview of 'multilateral total factor productivity', 'partial performance indicators' and 'activity and program-based benchmarking'.

a. Total Cost Benchmarking

Cost function estimation, which forms the basis for TCB, is a well-founded array of techniques that allows comparison of a firm's performance against that of others. It can provide insights into efficiency and best practices. An econometric cost function is a mathematical representation of the relationship between costs, production levels, the prices of inputs into the production process, and various business conditions. The selection of variables is guided by economic theory and industry-specific information. The overarching principle is that total costs depend, in the first instance, on the level of output and the prices the firm pays for capital goods, labour services, and other inputs integral to its production process. Typically, labour prices are determined by local market dynamics, whereas prices for capital goods are established in national or even international markets. Economic theory also offers insights into the nature or 'shape' of the relationship. For example, costs typically rise in response to inflation in input prices or an increase in the level of output. That is, costs are monotonically increasing in factor prices and levels of output. Cost function modeling can also be extended to settings where the firm produces multiple outputs, which is the case for electricity distribution companies.

Beyond output quantities and input prices, electricity networks contend with operational conditions contingent on their specific circumstances. Unlike firms operating in competitive industries, electricity distributors are obligated to furnish services to customers within prescribed service territories. An important factor influencing costs is customer density. For example, customers in urban settings require less 'wire per customer' than those in rural areas. A further relevant spatial feature is contiguity: utilities serving a contiguous area with customers throughout are likely to incur lower per-customer costs than those serving multiple discontiguous regions, even if the total customer count remains the same. One example of this is Entegrus Powerlines Inc. (serving a discontiguous region) compared to Oshawa PUC (which has a contiguous service area), with a similar number of customers. Fragmentation of the distribution areas can significantly influence costs as it can directly impact the assets necessary for service provision and maintenance. Moreover, the mix of customers can influence costs: the assets required for service delivery differ for residential, commercial, and industrial customers due to differences in demand levels, temporal patterns of demand, and load factors. Furthermore, urban areas with especially high density may necessitate greater distribution capacity to meet air conditioning load, thereby elevating per-customer costs due to the 'heat island' effect.[51]

Apart from customer characteristics, cost sensitivity extends to the physical environment of the service territory. Construction, operation, and maintenance costs of a given network are contingent on the physical terrain. Weather conditions can also influence costs. For instance, areas prone to high winds or severe weather events like ice storms typically incur higher costs due to increased equipment damage and service disruptions. Operating costs are further impacted by the type and density of vegetation within the territory. These conditions, intrinsic to the specific territory mandated for power distribution, lie beyond management control.

A mathematical representation of a total cost function may be written as follows:

$$TC = f\left(Q, W, Z, t\right) + \varepsilon \qquad (3.1)$$

where TC is total costs, Q represents output (which may be a scalar or vector), W is a vector of prices of inputs to the production process, Z is a vector of business conditions (e.g., customer density, age of assets) and t is a time trend term. In this specification, the function f is known to the modeler and it depends on a vector of parameters to be estimated by the researcher. The 'residual' ε is intended to capture random or unobserved components influencing costs. It is common for many of the variables to be expressed in logarithmic terms.

Conventional econometric cost function estimation has typically begun with the specification of a functional form for f.[52] Parameters linked to the variables in the cost function are then estimated using econometric methods. Estimation techniques, such as ordinary least squares (OLS) regression and its variants, or maximum likelihood estimation are widely used to estimate parameters using observed data. Parametric models may impose distributional assumptions on the error term ε and require careful model specification and testing to avoid inefficiency and bias in estimation.

One of the simplest specifications is given by

$$\ln TC = \beta_0 + \beta_1 \ln Q + \beta_2 \ln W_L + \beta_3 \ln W_K + Z\delta_Z + \gamma t + \varepsilon \qquad (3.2)$$

where Q is the level of output, W_L and W_K are prices of labour and capital, Z is a vector of business conditions, and t is the time trend term. In an industry where there is productivity

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[51] In this connection, it may be helpful to examine and compare load duration curves across distributors. Distributors with a high density of customers may display a particularly 'spikey' load duration curve.

[52] The *translog* specification is commonly used. As we will discuss later in the report, parametric specifications may impose unnecessary restrictions, potentially distorting or biasing the results. Modern techniques offer avenues to reduce reliance on functional form assumptions.

growth, one would expect γ, the coefficient of t, to be negative, reducing total costs over time, other things equal. In models that have been used for total cost benchmarking of Ontario utilities, the coefficient of the trend term plays an important role in estimating productivity growth.

In order to estimate such models, historical data for multiple firms are assembled on costs, levels of output, factor prices and measurable business condition variables. Such datasets combine both cross-sectional information (across firms) and temporal information (i.e., over time).[53]

Cost function estimation for benchmarking poses several challenges and considerations. Most important among these are:[54]

- Data Quality: Cost function estimation requires reliable data on input quantities, output levels, prices, and other relevant variables. Data errors or inconsistencies can lead to biased estimates and inaccurate benchmarking results. Failure to incorporate important and relevant variables can also result in biased results.[55]

- Model Specification: Choosing an appropriate functional form and specifying the correct model structure is crucial for accurate estimation. Misspecification of the model can lead to biased parameter estimates and incorrect benchmarking conclusions.

There are various extensions to this econometric cost function estimation framework, such as quantile regression, stochastic frontier analysis, more flexible modeling methods,[56] and panel data techniques mentioned above.

Benchmarking results must be interpreted carefully as there may be important variables that are not available in the data and whose omission can distort or bias results.[57] Nevertheless, cost function estimation is a powerful tool for assessing firm performance, identifying best

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[53] These require ‘panel data techniques’, which attempt to account for unobserved differences (heterogeneity) and time-varying factors that can affect costs. Panel data analysis allows for the identification of firm-specific effects and time trends in cost behavior, which can enhance the accuracy of benchmarking results.

[54] In addition to the items described below, ‘endogeneity’ issues can arise when explanatory variables are correlated with the error term, leading to biased estimates. Instrumental variable techniques can be used to address endogeneity and ensure the validity of benchmarking results.

[55] For example, benchmarking of distributors in Ontario has required considerable effort to assemble reliable data on capital costs. Much progress has been made in developing sound capital data since the Board began benchmarking using cost function estimation.

[56] Such as semiparametric estimation, see, e.g., Yatchew (2001, 2003).

[57] For example, Toronto Hydro has argued that congestion in its service areas has significant impacts on its costs. The company has put forth models which incorporate congestion.

practices, and driving efficiency improvements. By applying econometric methodologies to empirical data, analysts can quantify cost structures, compare performance levels, and derive insights to inform decision-making at the firm, industry, and regulatory levels.

TCB offers the advantage of distinctly identifying how changing business conditions influence costs and productivity. Unlike the index-based approaches which lack this level of identification of cost drivers, the cost model facilitates a nuanced understanding of productivity dynamics, especially pertinent amidst the evolving policy and technological landscape. Moreover, the cost model, once estimated, serves as a valuable tool for comparing efficiencies among distributors, providing a comprehensive overview of the productivity estimation process.

b. Total Factor Productivity Analysis

As noted, TFP estimation is an index approach based on an intuitively compelling concept. It involves comparing the growth rate of inputs used in a production process with the growth rate of the outputs produced. Productivity growth is defined to be the difference between the growth of outputs and the growth of inputs.

Effective implementation of this index approach requires that one undertake a series of steps, starting with the determination of the quantities of each production input, such as labour and capital. This initial phase presents its own challenges. Quantification of labour involves more than simply tallying the number of employees or labour hours; it requires a methodology for aggregating different types of labour, such as line workers, technicians, system operators, administrative staff, and management. A common strategy is to construct a labour price index and then use this index to convert labour expenditures into a quantifiable labour quantity index. However, this approach merely shifts the challenge, requiring the creation of a comprehensive labour price index that effectively consolidates various employee categories.

Electricity distribution involves multiple outputs, such as customer numbers, capacity and deliveries. A reliable methodology is required to amalgamate these types of output. In its 2013 submission, the PEG imported coefficient estimates from the TCB model to assign weights to each output. This is an important point -- although the TFP approach might appear to be more transparent, it actually relies on initial estimation of weights for individual outputs, for example, by estimation of a TCB model. In a sense, therefore, it is less transparent than a pure TCB approach.

After completing these preparatory steps, a comparison of the growth of the output index to that of the input index allows for the assessment of productivity growth. Although this interpretation seems straightforward and transparent, its reliability hinges on the accuracy and robustness of the preceding steps and underlying assumptions.

Conversely, estimating productivity growth using the TCB model involves a more streamlined and direct process: productivity growth is the estimate of the 'trend' or time coefficient in equation (2). Furthermore, the TCB model permits direct decomposition of productivity growth into its constituent components: technological improvements and scale economies.[58] The technology effects are directly obtained from the trend coefficient, and scale effects are readily calculable from the estimated coefficients. Conventional TFP approaches do not permit this kind of direct decomposition.[59]

Despite the widespread use of index models, often due to limited availability of data needed for cost models, it would be imprudent to rely solely on the former when the latter can offer more comprehensive insights. Given the capabilities to perform a more detailed analysis, it seems advisable to leverage this advanced approach to gain a fuller understanding of the underlying issues.

That is not to say that the TFP approach should be set aside: if both methods are applied and found to yield similar results, this provides a measure of reassurance in the findings. If they are found to be materially different, then this should trigger an investigation into the reasons for any differences.[60] In short, TFP may be used as a diagnostic tool.

The challenges and shortcoming of TFP may be summarized as follows:

- TFP does not readily allow for the incorporation of business conditions, noise in the data, or statistical testing.

- TFP calculations depend heavily on accurate aggregation of inputs (labour, capital, and materials) and outputs (peak capacity, electricity volumes, number of customers served). Inaccuracies or inconsistencies in these aggregations can significantly affect the results.

- TFP analysis does not capture the economies of scale that exist in electricity distribution. Larger or more diversified utilities might have operational advantages or disadvantages that TFP does not adequately reflect.

- TFP cannot separately account for technological advancements. As the electrical distribution industry evolves with new technologies, these changes can affect productivity in ways that TFP does not capture. Nor can qualitative improvements be distinguished.

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[58] It is also possible to estimate the effects of scope economies in a regression setting. This aspect may become more relevant as the scope of operations expands for distributors. Yatchew (2000) found significant scope effects for utilities which provided services beyond electricity distribution.

[59] Drawing a parallel with medical diagnostics, the index model can be likened to an X-ray which produces a two-dimensional image, offering basic insights, while the cost modeling approach is more comparable to an MRI, producing a three-dimensional image, and providing a more detailed, and clear basis for diagnosis.

[60] Attempts to reconcile results can even lead to identification of errors in data or coding.

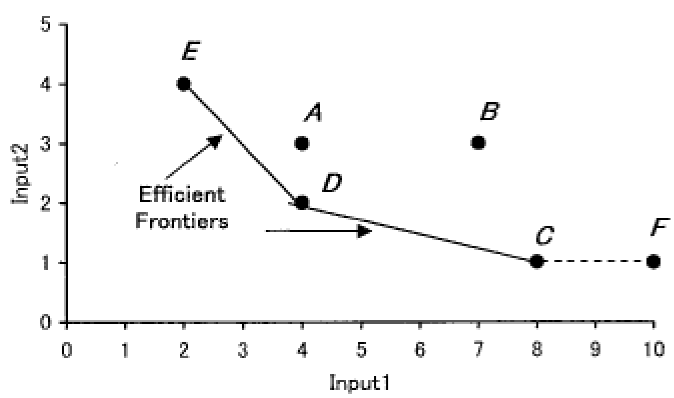
- TFP may not account for external factors such as regulatory changes, economic conditions, and environmental policies, which can have a significant impact on the productivity of electrical distribution companies.

- While unnecessary complexity should be avoided, it is not always practical or desirable to rely on apparently simpler, index-based TFP estimates when calibrating X-factors.

- Finally, while TFP may lend the appearance of simplicity (growth of inputs vs growth of outputs), the construction of input and output indices relies upon aggregation coefficients that are often estimated using a cost function approach such as TCB.[61]

c. Data Envelopment Analysis

DEA is a non-parametric method used to evaluate efficiency across organizations or companies operating under similar conditions. Unlike parametric techniques that require a predefined functional form to represent the production function, DEA employs an empirical approach to construct a production frontier. This frontier is used as a benchmark to assess the efficiency of various firms by comparing their performance. Efficiency is calculated based on the ratio of weighted outputs to weighted inputs for each entity, without assuming a fixed relationship between these inputs and outputs.



DEA is based on linear programming techniques, specifically the concept of frontier analysis. It formulates a linear programming model to determine the relative efficiency by maximizing outputs subject to a set of constraints on inputs. For illustrative purposes, consider the

[61] More generally, attribution of TFP growth to factors and drivers is, in principle, possible. This can be accomplished by first estimating the TCB model to obtain relevant elasticities. See, Empirical Research in Support of Incentive Rate Setting in Ontario: Report to The Ontario Energy Board, Pacific Economics Group, May 2013, Appendix One: Econometric Decomposition of TFP Growth, pp. 101-104.

following setting illustrated in the figure.[62] Firms A through F produce one unit of output using various combinations of two inputs. The efficient frontier is determined by firms E, D, C and F. It represents the boundary of attainable efficiency levels for firms in the dataset. Firms A and B lie above the frontier and are classified as inefficient.

DEA evaluates the relative efficiency of each firm by comparing its observed input-output ratios to those of other firms. Those that lie on or close to the efficiency frontier are considered efficient, while those above the frontier are deemed inefficient. DEA allows for benchmarking by identifying the most efficient firms as benchmarks or reference points for less efficient firms. This enables managers to compare their organization's performance to industry peers or best practice standards and identify opportunities for improvement. This technique has been used in conjunction with TCB to identify variables for validation of TCB trends.

Each firm receives an efficiency score relative to this frontier, with a score of 1 (or 100%) indicating optimal efficiency and positioning on the frontier itself. Scores below 1 suggest inefficiency, highlighting potential areas where input usage can be optimized for enhanced output performance. DEA not only identifies the most efficient practices but can also set performance targets and may offer actionable insights for less efficient firms.

DEA enables organizations to gauge their efficiency by comparing their input-output ratios against firms that are on or near the frontier. It facilitates benchmarking by recognizing the most efficient firms as benchmarks for others. This comparison helps managers align their firms with industry standards or the best practices, identifying areas for improvement.

A significant advantage of DEA is its reliance on actual performance data rather than statistical models, providing a practical assessment of firm efficiency. However, one limitation is that DEA does not account for stochastic variations and measurement errors and, in its basic form, does not consider varying business conditions. This can limit its applicability in environments where external factors significantly impact operational outcomes.[63]

DEA is widely used in Europe. Its ability to accommodate multiple inputs and outputs without needing to specify a functional form makes it highly adaptable and applicable across various sectors. Unlike econometric models, DEA does not require assumptions about the underlying functional form of the production process. DEA provides benchmarks by identifying 'best practice' frontiers. In regulatory frameworks, especially in utilities and public services which are prominent in Europe, DEA helps in setting performance standards and monitoring efficiency. The method's ability to provide a detailed efficiency analysis without requiring cost data (which may be difficult to obtain accurately) makes it useful. DEA can often be simpler and more cost-effective to implement compared to developing and estimating complex econometric models.

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[62] Adapted from Cooper, W. W., Seiford, L. M., & Tone, K. (2006). Introduction to data envelopment analysis and its uses: with DEA-solver software and references. Springer Science & Business Media., pp. 27-30.

[63] See, e.g., Giannakis, D., Jamasb, T., & Pollitt, M. (2005).

The advantages of DEA may be summarized as follows:

- DEA involves direct comparisons of firms to each other, rather than to statistical models and measures.

- DEA does not require the specification of a functional form relating inputs to outputs. This flexibility allows it to be used across various industries and scenarios without requiring predefined models.

- DEA effectively identifies distributors that perform best under given circumstances. It constructs an efficiency frontier from the data itself, using the best-performing distributors as benchmarks.

- DEA can handle multiple inputs and outputs, providing a comprehensive view of organizational efficiency.

- DEA provides detailed comparative efficiency analyses, allowing organizations to identify leaders in efficiency and model their operations accordingly. This is particularly useful for internal benchmarking and continuous improvement.

The disadvantages may be summarized as follows:

- DEA results are highly sensitive to data quality. Any errors in data collection can significantly affect the outcomes, making it crucial to have accurate and reliable data. Furthermore, DEA is highly sensitive to outliers. Some firms might display a degree of efficiency that may not be feasible for other firms because of differing business environments.

- DEA does not account for statistical noise; all deviations from the frontier are considered inefficiencies. This can be problematic in environments where data variability is due to factors beyond the control of the observed distributors or to random events.

- The results of DEA can be sensitive to the scale of operation. The relative efficiency of distributors might change with the size of the data set or the range of observed operations, potentially skewing comparisons.

- In its basic form, DEA does not integrate external environmental factors that might affect performance, though extended models of DEA aim to address this limitation.

- While DEA is powerful, it can be complex to implement and interpret. Understanding DEA results and translating them into actionable strategies requires a deep understanding of the method and its implications.

On balance, the availability of detailed cost and business conditions data in the Ontario setting gives TCB important advantages over DEA. While the lack of parametric assumptions in DEA is seen to be a positive attribute, TCB can be readily adapted to reduce dependence on functional form assumptions through flexible modeling techniques that have been discussed above

d. Stochastic Frontier Analysis

SFA is a parametric statistical method designed to assess the efficiency of firms by evaluating their output production from given inputs. Unlike DEA, which does not assume any specific functional form, SFA relies on a predefined cost function and explicitly accounts for noise or statistical error within the data. This approach differentiates between inefficiency effects and random disturbances, attributing output deviations to these distinct sources. The efficiency of a firm is gauged by its proximity to the established efficiency frontier, with those on the frontier deemed fully efficient.

SFA introduces a two-part error term in its model: the first captures random shocks and measurement errors (noise) that impact output levels but are assumed to be outside the firm's control; the second reflects inefficiencies. The main part of the model (the deterministic portion) allows for the consideration of varying business conditions, enhancing its practical applicability. SFA can be implemented by simply adding the two-part error term to the TCB specification.

More precisely, consider the following modification to the total cost function in equation (3.1):

$$TC = f\left(Q, W, Z\right) + \varepsilon + \eta \qquad (3.1a)$$

whereas before TC is total costs, Q represents output (which may be a scalar or vector), W is a vector of prices of inputs to the production process, and Z is a vector of business conditions (e.g., customer density, age of assets). In this specification, the function f is known to the modeler and it depends on a vector of parameters to be estimated by the researcher. The residual ε is a random term, often assumed to have a normal distribution. The second error component η is a non-positive random variable[64] representing technical efficiency. A distributor with a large negative η is seen as achieving lower costs. The stochastic frontier represents the minimum attainable level of costs for given levels of observable variables. In effect, SFA augments the econometric modeling of cost functions by incorporating an additional error term to account for technical inefficiency.

[64] This inefficiency term is assumed to follow a specific distribution, such as a half-normal or exponential.

Utilizing standard statistical techniques (such as maximum likelihood estimation), SFA estimates both the parameters of the cost function and the inefficiency terms simultaneously. This separation of systematic and random output components enables estimation of technical efficiency, allowing firms to benchmark against industry standards or best practices.

Despite its apparent utility, SFA's major limitation lies in its reliance on specific assumptions regarding the probability distributions of the error components. Alterations in these distributional assumptions can significantly change the analytical outcomes. Moreover, SFA is sensitive to outliers, as a few data points with substantially negative efficiency estimates (recall that negative values of η correspond to lower costs and greater efficiency) can disproportionately influence overall efficiency assessments. This vulnerability necessitates careful consideration and potentially the integration of methods to manage outlier impacts.[65]

In the Ontario context, it may be helpful to estimate the SFA model as an augmentation to the TCB specification.

e. Multilateral Total Factor Productivity

Many electric distribution benchmarking methodologies employ total factor productivity (TFP) analysis to compare the ratio of outputs to inputs across firms and measure productivity growth. However, traditional TFP methods fall short in robustly assessing relative efficiency. To address this, methods like the Multilateral Total Factor Productivity (MTFP) and Multilateral Partial Factor Productivity (MPFP) have been proposed and adopted, as demonstrated by the Australian Energy Regulator (AER).[66]

TFP analysis in a time-series context tracks the change in the ratio of weighted averages of outputs to inputs over time. In contrast, Partial Factor Productivity (PFP) focuses on specific inputs like operational expenses or capital inputs, rather than all relevant inputs. Commonly used indices include the Fisher ideal index and the Törnqvist TFP change index. The Törnqvist index allows for a decomposition of the contributions of changes in each output and input, which is a desirable property for specific comparisons of firms.

However, these indices, while effective for bilateral comparisons of productivity change rates between firms, do not support robust comparisons of absolute productivity levels in panel data due to their non-transitive nature. This property states that direct comparisons between observations should yield the same results as indirect comparisons through an additional observation. For example, the Törnqvist TFP index violates this property, since for a given time period, comparing firm *m* and *n* does not yield the same results as comparing firm *m* to firm *k* and then comparing firm *k* to firm *n*. As such, indices that violate the transitivity property are

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[65] See, e.g., Yatchew (2001) paper on yardstick competition.
[66] Lawrence, D., Coelli, T., & Kain, J. (2018). Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Annual Benchmarking Report.

not ideal for ensuring consistent direct and indirect cross-section comparisons between multiple firms.

To overcome this limitation, Caves, Christensen, and Diewert (1982) introduced the MTFP index.[67] In essence, this index compares each firm observation in a given period to a hypothetical firm with average output quantity, input quantity, revenue shares and cost shares. This index adopts a translog specification and maintains the transitivity property. There may be minor differences when compared to the Törnqvist TFP index. This makes the MTFP index preferable for cross-sectional comparisons of multiple firms, though traditional TFP indices are more suited for analyzing the time-series performance of individual firms.

In Australia, the AER has implemented the MTFP index to benchmark the productivity of electric distribution and transmission. Variants like the MPFP are also used to evaluate the contributions of different inputs, such as operational expenses and capital.

MTFP methodology is particularly useful in regulated, non-competitive environments where firms do not price outputs solely based on costs, such as in electric distribution. Instead, the methodology takes a functional approach to measuring outputs, focusing on factors that reflect customer value and regulatory revenue considerations, rather than solely on distributor billing practices. Key outputs include energy throughput, ratcheted maximum demand, customer numbers, circuit length, and service interruptions. Relevant inputs encompass operational expenses, both overhead and underground lines and cables, and transformer capacities. Ratcheted maximum demand is a type of billing method whereby the peak demand of a large user is used to set baseline peak demand in future years.

The cost shares inputs are calculated using a multi-output Leontief cost function, under the assumption that DNSPs use inputs in fixed proportions for each output. This approach enables robust analysis of DNSP efficiency and effectiveness, supporting regulatory oversight and industry benchmarking. However, as MTFP is a deterministic method, traditional cost estimation methods are employed alongside to provide confidence intervals, enhancing the reliability of the productivity measures.

f. Partial Performance Indicators

The Australian Energy Regulator has relied on Partial Performance Indicators (PPIs). These are described as “a simpler form of benchmarking that compares inputs to one output. This contrasts with the MTFP (multifactor total factor productivity), MPFP (multi-product total factor productivity) and econometric techniques that relate inputs to *multiple* outputs”.[68] They

[67] Caves, D. W., Christensen, L. R., & Diewert, W. E. (1982). Multilateral comparisons of output, input, and productivity using superlative index numbers. The economic journal, 92(365), 73-86.
[68] Australian Energy Regulator. (2022). 2022- Annual Benchmarking Report - Electricity distribution network service providers. Commonwealth of Australia. November 2022, p. 37.

are used to support general benchmarking methods, the rationale being that they can be used to compare the efficiency of distribution network service providers (DNSP's) in providing a specific output or service, as opposed to finding general efficiencies.

Three cost PPIs are considered: total cost per customer, total cost per circuit length kilometre, and total cost per megawatt (MW) of maximum demand. In terms of total cost per customer over the period 2017 -2021, CitiPower and United Energy had comparatively low total costs per customer, and very high average customer density (> 100 per kilometer). With respect to total cost per kilometre of circuit line, high density companies tend to spend more, possibly due to the difficulties of installation and maintenance in larger metropolitan areas.

Partial Performance Indicators can also be used for benchmarking other sub-categories. The 2022 AER Annual Benchmarking Report specifies category level opex variables including vegetation management, maintenance, emergency response, among others. PPI can be informative in developing an understanding of how individual inputs are related to outputs.

g. Activity and Program Based Benchmarking[69]

Comparison of costs for activities and programs at various degrees of granularity has been a longstanding useful exercise conducted by regulators and utilities in various jurisdictions. The OEB Activity and Program-based Benchmarking Initiative (APB) comprises a formalization of this process. It serves as a complement to TCB and represents another example of yardstick competition which the Board can incorporate within its regulatory process. The objective is to benchmark various subsets of distributor costs. The AER and the Office of Electricity Regulation and Office of Gas Supply (Ofgem) employ these types of analyses for electricity distributors.

Since launching its concept paper in 2018, the PEG has conducted statistical (regression) analyses of ten activities/programs. High quality granular data is essential to the utility of APB. These areas included billing O&M, meter O&M, vegetation management O&M, lines O&M, distribution station equipment O&M, maintenance of poles, towers, and fixtures, and capex for distribution station equipment, poles, towers, fixtures, line transformers, and meters.

APB offers several benefits for customers, utilities, and the OEB. For customers, it can lead to cost savings as continuous improvement in cost performance may result in lower rates. It also encourages utilities to meet customer service and energy reliability expectations, and the transparent framework for data gathering, analysis, and reporting can boost customer confidence in energy regulation.

[69] See, Activity and Program Benchmarking of Ontario Electricity Distributors, PEG Report to the Board, December 2018; OEB Staff Discussion Paper: Activity and Program-based Benchmarking, Ontario Energy Board (2019); and . Activity and Program-based Benchmarking – Unit Cost Report , Pacific Economics Group (2023).

From the utilities' perspective, the APB allows for performance comparison across different utilities, identifying those that excel in specific areas and facilitating the sharing of best practices. This competitive environment promotes productivity and profitability improvements. Additionally, the APB focuses on targeted areas, potentially reducing the duration of reviews and increasing regulatory efficiency.

For the OEB, APB supports the objective of encouraging continuous improvement in utility operations while meeting customer expectations for reliable service. Consistent performance reporting enables the OEB to compare utilities' performance in key programs. APB serves as a screening tool, allowing the OEB to concentrate its reviews on the most important issues, potentially leading to more efficient rate application reviews. By complementing total cost benchmarking with detailed assessments of significant activities and programs, the APB facilitates a comprehensive evaluation of utility performance. Year-over-year performance tracking for individual utilities helps understand performance trends.

In ratemaking, performance analysis can support the review of investments and expenses requested for targeted programs in future rate applications. APB can also be used to design performance incentives.

APB can aid policy development by providing insights into specific program performance across the industry, supporting the development of regulatory policies as needed. In the context of rate-setting, APB results can inform the OEB and other stakeholders about areas requiring detailed review in rate applications, leading to more proportionate reviews and other regulatory investigations. Additionally, APB can help the OEB assess a utility's ability or readiness to adapt to the changing needs of Ontario customers as the sector evolves. As an informational tool, APB can guide individual distributors in seeking increased cost efficiencies by adopting best practices from the best-performing distributors.

4. Evaluation of the Current TCB Methodology

a. The Model[70]

As noted, TCB is employed to assess distributor cost efficiency using econometric techniques. Distributor costs are modeled as a function of the common and unique business conditions faced by each distributor. These conditions encompass factors such as customer base, the prices of essential inputs such as labour and capital, and other business conditions. Parameters within the model establish the relationship between each business condition and the distributor's cost. Certain parameters currently in use were originally derived for the EB 2010-0379[71] proceeding (which concluded in 2013) using Ontario distributor data spanning from 2002 to 2012.

A more complete representation of the TCB model relative to equation (3.2) is given by:

$$
\begin{aligned}
\ln TC_{it} = \quad & \beta_0 + \sum_j \beta_j \ln Q_{j_{it}} + \sum_m \beta_m \ln \mathrm{W}_{m_{it}} \\
& + \frac{1}{2}\left(\sum_j \sum_l \gamma_{jl} \ln Q_{j_{it}} \ln Q_{l_{it}} + \sum_m \sum_n \gamma_{mn} \ln \mathrm{W}_{m_{it}} \ln \mathrm{W}_{n_{it}} \right) + \sum_j \sum_m \gamma_{jl} \ln Q_{j_{it}} \ln W_{m_{it}} \qquad (4.1) \\
& + \sum_p \delta_p z_{p_{it}} + \delta t + \left(u_i + \varepsilon_{it} \right)
\end{aligned}
$$

where TC_{it} is total costs; $Q_{j_{it}}$ is the quantity of output j for $j = 1,\dots,J$; $W_{m_{it}}$ is the price of input factor m for $m = 1,\dots,\mathrm{M}$; $z_{p_{it}}$ is business condition variable p for $p = 1,\dots,P$; t is time trend; and the composite error $u_i + \varepsilon_{it}$ consists of a time-invariant firm-specific effect combined with a transitory effect. Elaborate as this model may appear, it can be routinely estimated using standard econometric packages. Equation (4.1) represents one of the models which will be estimated during the statistical phase of this project.

In models that have been used for total cost benchmarking of Ontario utilities, the coefficient of the trend term plays an important role in estimating productivity growth. If there is productivity growth, one would expect δ, the coefficient of t, to be negative, reducing total costs over time, other things equal. Notably, in the EB 2010-0379 proceeding, and contrary to

[70] The main sources for the Model and Data sections of this portion of the report are "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, Pacific Economics Group, May, 2013"; "EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, Ontario Energy Board, November 21, 2013; and regular updates to the modeling, e.g., "Empirical Research in Support of Incentive Rate-Setting: 2021 Benchmarking Update Report to the Ontario Energy Board, Pacific Economics Group, July 2022".

[71] Available at https://www.oeb.ca/sites/default/files/uploads/EB-2010-0379_Report_of_the_Board_20131121.pdf

expectations, both the PEG and the Electricity Distributors Association estimated δ to be *positive*, suggesting *negative* measured productivity growth.[72]

The model can project total costs for each distributor by multiplying the distributor's business condition variables by the model parameters and summing the results. By comparing the actual cost of the distributor to the predicted cost, one can gauge the cost performance. Distributors with actual costs below predicted costs are deemed superior with respect to cost performance.

The relative efficiency then informs the assignment of stretch factors. These are recalculated usually on an annual basis using updated values for the variables in the model. However, it is our understanding that the parameters (i.e., the coefficients) in equation (4.1) have remained unchanged, fixed to the values estimated by PEG in 2013. The OEB chose not to update the model parameters with future data in order to establish a consistent benchmark for distributors to showcase ongoing improvements in cost performance, enabling them to earn lower stretch factors.

b. The Data

The cost and output data used for calculations originate from distributors and are sourced from their Reporting and Record-keeping Requirements (RRR) filings. The data adhere to the accounting policies and procedures outlined in the Accounting Procedures Handbook for Electricity Distributors, inclusive of the Uniform System of Accounts and other instructions within the RRR filing system. The OEB mandates that distributors maintain the integrity of their reported data and outlines reporting procedures to enhance data quality. OEB Staff conduct reviews and approve distributor requests for data corrections if reasonable justifications are provided.

Aside from the RRR, data sources related to input prices were obtained from various entities. OEB-approved rates of return were acquired from OEB Staff, while other input price data came from Statistics Canada. The input price indexes utilized were mostly consistent with those in PEG's 2013 study, except for the Electric Utility Construction Price Index (EUCPI), which is no longer calculated by Statistics Canada. To address this, the growth in the Gross Domestic Product Implicit Price Index Final Domestic Demand (GDPIPI FDD) was used to adjust the EUCPI values for the calculations.

The updating process mirrored the original work, with improvements in data quality related to capital additions. Consequently, more accurate data from 2013 to 2021 were utilized instead of inferring these data from changes in gross plant. Adjustments were also made for mergers that occurred post the initial study, with historical cost performance calculated based on the combined entity's predecessors.

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[72] In subsequent investigation of these data, Dimitropoulos and Yatchew (2017) obtain a similar result.

c. Calculation of Stretch Factors

The updated stretch factors are calculated based on the difference between the actual cost and the predicted cost averaged over the most recent three-year period. According to the Board Report, distributors that maintained an average cost of 25% or more below the predicted cost were assigned the lowest stretch factor of 0%. Those with an average cost between 10% and 25% below the predicted cost were assigned a stretch factor of 0.15%. Distributors falling within 10% of the predicted cost were allocated a stretch factor of 0.30%. For distributors whose costs were between 10% and 25% higher than the predicted cost, the stretch factor was set at 0.45%. Companies that had costs exceeding 25% more than predicted were given the highest stretch factor of 0.60%. In the annual revisions, the majority of companies maintain their stretch factors. The stretch factor is used only to adjust the permitted rate increase through the incentive regulation formula. The reference benchmark value is the predicted cost based on the econometric TCB model, unadjusted for any stretch or productivity factors.

d. Possible Modifications and Variations to TCB Methodology

As noted earlier, the TCB model finalized by PEG in 2013 has not been updated. For purposes of retaining stability, the parameters have been retained for about a decade. It is an opportune time to re-estimate the model and to consider some possible modifications, especially since we now have an additional decade of data.

i. Productivity Trends

The productivity trend in the TCB framework is estimated as the coefficient of time trend. In equation (4.1), this is δ, the coefficient of t. The reference 2013 model has an estimated coefficient of 0.12; the *positive* value indicates *negative* productivity growth. This may be possibly due to the absence of relevant data and a changing industry environment.[73] In the result, the OEB assigned an X-factor of zero.

[73] Some have provided possible explanations for this counterintuitive result. For example: "The attribution of the apparent productivity slowdown to specific causes is a more delicate matter, given the available data. We suggest that there are at least three contributory factors. The first is the overall slowdown in load growth, which in turn is the result of two trends—substantial increases in Ontario electricity prices, and conservation programs mandated by the regulator. … The second is aging of infrastructure which in Yatchew (2000) was shown to have a material and statistically significant impact on costs (the current data do not contain age-related variables). The third concerns the additional tasks and services required of distributors … During the sample period there have been substantial changes in the Ontario electricity industry which have impacted distributors. These include integration of renewables and other distributed generation, increased focus on conservation and demand management, and implementation of smart grid and smart meter programs. Smart technologies may, in time, lead to improved productivity. However, we note that despite rapid adoption of computers during the 1980's the impact on productivity was not observed until much later. … Electricity distribution is likely undergoing a similar transformative process." D. Dimitropoulos and A. Yatchew. "Is productivity growth in electricity distribution negative? An empirical analysis using Ontario data." The Energy Journal 38, no. 2 (2017).

Productivity growth can vary significantly year-to-year.[74] Estimation of an average productivity term can reduce volatility. On the other hand, it does not contribute to our understanding of productivity *trends*. Three variations are worth considering:[75]

- incorporating separate trend coefficients over sub-periods of the data;
- incorporating a trend *function* which varies smoothly over time; the shape of the estimated trend function can detect the direction in which productivity is trending;[76]
- assessing whether there have been discrete shifts in productivity.[77]

As distribution industries face challenges, it may be more appropriate to base X-factors on recent productivity patterns and trends, rather than an average over many years. This can be facilitated by flexible estimation of the trend effect.

ii. Flexible Specifications and Robustness Checks

Flexible econometric modeling, often referred to as 'nonparametric' or 'semiparametric' modeling, has several advantages, depending on the context and specific application. Flexible models can capture complex and nonlinear relationships among variables. They are not constrained by restrictive assumptions about the underlying shape of the relationship, making them versatile in handling diverse data types. In particular, they do not assume a specific functional form for the model, unlike parametric models such as linear regression. This makes them more robust in situations where the true data-generating process is unknown or cannot be accurately represented by a simple model.[78]

In the present context, their primary benefit is in exploratory analysis. They can reveal important features and interactions that may not be apparent when estimating parametric models. They may also be used to validate parametric specifications. Flexible models can be less

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[74] This was an important area of discussion in the 2008 proceeding. See: Pacific Economics Group (2008, February). *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario, Report to the Ontario Energy Board.* https://www.oeb.ca/documents/cases/EB-2007-0673/PEG_Report_20080228.pdf.

[75] It is our intention to test these variations during the statistical analysis portion of this project. In the 2013 PEG report, the TFP approach reflected a productivity slowdown over the span of years included in the analysis.

[76] Flexible trend estimation is well-understood, see e.g., EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Ontario Energy Board, September 17, 2008. A graphical representation of productivity trends in that proceeding may be found in "3rd Generation Incentive Regulation for Electricity Distributors: EB-2007-0673, Comments on behalf of the Electricity Distributors Association, Prepared by Adonis Yatchew, Ph.D. May 16, 2008." Figure 2, p. 9.

[77] These are sometime called 'regime-shift' models.

[78] Conventional regression estimates conditional mean relationships. Quantile regression estimates conditional median and conditional quantiles. For a discussion of possible applications in an incentive regulation setting, see A. Yatchew, 2001: "Incentive Regulation of Distributing Utilities Using Yardstick Competition", Electricity Journal, Jan/Feb, 56-60.

sensitive to outliers compared to parametric models like linear regression.[79] This can be advantageous when dealing with noisy or heterogeneous data where outliers are common. Widely used statistical and econometric platforms typically have functions and subroutines that permit easy implementation.[80,81] Flexible models can be prone to overfitting, where too much of the variation is attributed to explanatory factors rather than to unexplained or random variation. However, well established techniques (in particular, cross-validation) effectively mitigate this issue. Flexible models may require larger datasets to effectively capture unusual patterns in the data. On the other hand, while parametric models with fewer parameters may be simpler, they can blur or even entirely overlook important nuances in the data.

Overall, flexible modeling can be a powerful tool for analyzing complex data and uncovering hidden patterns, conducting exploratory analyses, validating parametric specifications and identifying recent trends.

iii. Improving Precision of Cost Function Estimation

Direct estimation of cost functions, (i.e., the TCB model) has associated with it a degree of statistical uncertainty, usually characterized by 'confidence intervals' or ranges around parameters. Precisely estimated parameters will have tight confidence intervals, while imprecisely estimated parameters will have wide intervals. Precision can often be improved by incorporating data on the quantities of factor inputs (such as labour and capital) as cost functions and factor inputs share a common set of parameters.[82] Expanding model estimation

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[79] In earlier benchmarking proceedings, Pacific Economics Group has identified two outliers in the Ontario distributor data: Toronto Hydro-Electric System Limited and Hydro One Networks Inc.

[80] For example, additively separable flexible (nonparametric) specifications can be implemented using three lines of code in *R*.

[81] It is also worth noting that even the reference model approach proposed by Schleifer (1986) and used by the Pacific Economics Group requires estimation of over 70 separate regression models, one for each utility in the sample. Projected costs for each utility are based on a regression which omits that utility from the sample to reduce bias. In effect, each projection is an out-of-sample prediction.

[82] Shepherd's lemma is a concept commonly used in microeconomics and econometrics, particularly in the analysis of production and cost functions. It is a special case of the 'envelope theorem'. Shepherd's lemma links the partial derivatives of a cost function with respect to input prices to the firm's input demand functions. Mathematically, Shepherd's lemma states that the partial derivative of the cost function with respect to the price of an input factor is equal to the quantity of that input demanded by the firm at the given input price. By applying Shepherd's lemma, economists can derive the firm's input demand functions directly from the cost function, which simplifies the estimation process and provides additional constraints for estimating cost function parameters.

Using Shepherd's lemma can improve the estimation of cost function parameters by incorporating economic theory and firm behavior into the modeling framework. It helps ensure that the estimated cost function is consistent with the firm's optimization behavior and market conditions. Factor demand data are especially useful to incorporate these additional data can be readily achieved using standard regression-type techniques. The 2013 PEG report recognizes the benefits of using factor demand data and it is incorporated in the distributor cost function estimation conducted by Dimitropoulos and Yatchew (2017).

The use of bootstrap techniques can improve the precision of parameter estimates (e.g., leading to more precise confidence intervals). These and other techniques for improving precision of estimation and testing for model robustness will be explored in the statistical portion of this study.

iv. Interjurisdictional Benchmarking Comparisons of Productivity

Interjurisdictional comparisons of productivity growth can be useful in identifying sources of productivity growth across different regions. Such comparisons may facilitate the identification of best practices. High-productivity industries can serve as benchmarks for others, highlighting areas where improvements can be made.

Regulators and policymakers can use interjurisdictional comparisons to evaluate the effectiveness of policies aimed at promoting productivity growth. By analyzing differences in productivity *trends* across regions with differing benchmarking frameworks, policymakers can assess which policies are more successful and which need adjustments.

Productivity growth often follows the adoption and diffusion of more efficient technologies. Interjurisdictional comparisons can help identify areas where technology adoption is driving productivity growth faster. This information can guide technology transfer initiatives and investments.

Differences in productivity growth rates may also reflect variations in human capital development and skills levels. Comparisons can highlight the importance of education, training, and workforce development in driving productivity improvements. Capital planners can use interjurisdictional comparisons to inform decisions about resource allocation and investment.

Disparities in productivity growth rates may indicate structural barriers[83] or inefficiencies in certain industries. Analyzing these differences can help identify systemic challenges that need to be addressed to unlock further productivity gains.

In summary, interjurisdictional comparisons of productivity growth offer valuable insights into the sources and drivers of productivity improvements. By identifying best practices,

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in improving precision in flexible (nonparametric) settings. See Hall, Peter and A. Yatchew 2007. Nonparametric Estimation When Data on Derivatives are Available. Annals of Statistics, 35:1, 300-323 and Hall, Peter and A. Yatchew 2010. Nonparametric Least Squares in Derivative Families. Journal of Econometrics, 157, 362-374.

[83] A useful example is the rules governing incentivization and integration of DERs. Alternative approaches to promoting renewables have led to different electricity cost impacts and adoption rates.

evaluating policies, promoting technology diffusion, investing in human capital, addressing structural barriers, and enhancing global competitiveness, these comparisons play a crucial role in fostering sustainable economic growth and development.

v. Data from Other Jurisdictions

There have been at least three instances of reliance on data from other jurisdictions in cost and productivity benchmarking of Ontario distributors:

- During 3rd Generation PBR completed in 2008, Ontario X-factors were based on U.S. distributor data. Ontario capital data were deemed inadequate to estimate cost functions for Ontario distributors. The PEG used data on 77 U.S. utilities over the period 1995-2006. Total cost benchmarking was apparently not feasible for the U.S. data, so PEG implemented a TFP approach.

- More recently, experts on behalf of THESL have filed models in CIR applications which rely minimally on Ontario distributor data and instead use numerous U.S. companies.[84] The underlying rationale for excluding other Ontario distributors was that THESL operated in a uniquely different high-density urban environment with aging legacy distribution infrastructure.[85]

- Similarly, the Clearspring report filed on behalf of Hydro One relies on 79 U.S. utilities and HONI in its statistical benchmarking analysis.

Both PEG and Clearspring underscore the benefits of interjurisdictional data:

> "The United States and Ontario have both produced large amounts of standardized electric utility operating data which are useful in benchmarking and productivity research. Unusually within Organization for Economic Co-operation and Development ("OECD") countries, these data permit total cost benchmarking and multifactor productivity ("MFP") studies to be conducted with reasonable accuracy as well as the benchmarking studies of utility operation, maintenance, and administrative ("OM&A") expenses which regulators consider in other countries (e.g., Australia)."[86]

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[84] In the 2020-2024 CIR application, the data consisted of six large Ontario utilities and 83 U.S investor-owned utilities. See, e.g., EB-2018-0165, Exhibit M1, Page 19, IRM Design for Toronto Hydro-Electric System, March 20, 2019, Mark Newton Lowry, Ph.D., Pacific Economics Group. In the 2025-2029 CIR application, the data consisted of 78 U.S. investor-owned utilities and Toronto Hydro. See, e.g., Econometric Benchmarking Study of Toronto Hydro's Total Cost and Reliability Metrics, Clearspring Energy Advisors, Steve Fenrick, October 31, 2023, Toronto Hydro-Electric System Limited, EB-2023-0195, Exhibit 1B, Tab 3, Schedule 3, Appendix A, ORIGINAL, (49 pages)

[85] EB-2018-0165, Exhibit 1B, Tab 1, Schedule 1

[86] "Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research", EB-2021-0110, 2022-06-13, Attachment 1, p.2. https://www.rds.oeb.ca/CMWebDrawer/Record/749177/File/document.

Furthermore, the Australian Energy Regulator has incorporated Ontario distributor data into their benchmarking analyses. In view of this, expanded use of data from other jurisdictions may prove useful in TCB (and other benchmarking approaches) of Ontario distributors.

vi. Additional Considerations

It may be useful to analyze productivity and efficiency results from more than one methodology. For example, in EB-2020-0379, PEG estimated both TCB models and TFP variants. In the event that the OEB or its experts use additional approaches, a comparison and reconciliation of the results could significantly contribute to our understanding of changes in productivity growth.

It may also be possible to incorporate reliability statistics, (such as SAIDI, CAIDI) within the TCB framework. Alternatively, separate statistical analyses of reliability statistics could be conducted. Both types of analyses could be incorporated into the calibration of the incentive regulation model.

As electricity distribution evolves, it would be appropriate to consider the incorporation of additional variables in the TCB modeling. For example, penetration rates of distributed energy resources such as solar, wind and storage, as well as EV charging systems might be material in explaining distributor costs.

e. Possible Modifications to Calculation of Stretch Factors

Two possible modifications could be considered. First, the stretch factor could include a component which reflects reliability and service quality. The incorporation of reliability within the incentive regulation mechanism has been adopted in certain other jurisdictions.[87]

A second possible modification would recognize the improvement of utility performance relative to its own past. Assigning stretch factors is challenging. While the same TCB model can estimate average industry efficiency well, it is less accurate for pinpointing individual companies. This is because industry efficiency is an average, while individual efficiency requires a separate prediction for each company, making it less reliable. Even small changes in how the model works can significantly alter a company's efficiency score. An analogy from sports may be helpful. The National Basketball Association has for four decades recognized the "Most Improved Player". Drawing on this idea, stretch factors could consider a company's progress over time, not just its current performance compared to others. Stretch factors could be based on a company's cost-saving improvements compared to its own past performance, not just against other companies. Thus, even if a company's costs seem high now, if they have been improving recently, they might still receive a more favorable stretch factor. This idea was

[87] For example, in the Netherlands and Australia. See Appendix B. Benchmarking Costs and Reliability in Other Jurisdictions.

proposed to the Board in 2013. In its Decision, the Board stated that "This architecture will be considered in the future."[88] The stretch factor could be assigned by combining the existing methodology with this approach.[89]

f. Evaluation of TCB Methodology

Here we summarize the advantages and disadvantages of TCB and our overall evaluation of the methodology employed by the OEB.

We begin with the disadvantages of TCB modeling. They require large quantities of data, and the effectiveness of these models heavily relies on data consistency across numerous firms. TCB models may appear complex which may pose challenges for non-experts due to their technical sophistication. These models are also sensitive to modeling assumptions, which can significantly influence the results. While TCB methods provide a structured way to analyze cost-efficiency, they may oversimplify the complexities inherent in electricity distribution systems, such as differences in age of assets, technology, and maintenance practices. Furthermore, the dynamic nature of electricity markets, influenced by technological advancements and policy changes, complicates the integration of such factors into TCB models. Another drawback is that while TCB focuses on cost-efficiency, it may not effectively capture other critical aspects such as service quality, reliability, and customer satisfaction. TCB may fall short in adequately accounting for regional variations like climate, customer density, and local regulations, all of which can impact both costs and performance.[90]

On the other hand, TCB offers various advantages. It can attribute cost effects to specific factors or operating conditions, thus providing a clear insight into the drivers of cost differences. It allows for the separate identification of scale, scope, and technology effects, enhancing the understanding of how various elements contribute to overall costs. Employing standard statistical techniques, TCB provides a reliable basis for estimating output weights as inputs to Total Factor Productivity (TFP) analysis. The flexibility of these models is another advantage: they can be readily modified to incorporate different functional forms or to conduct robustness checks, enhancing their adaptability to various analytical needs. TCB also supports rigorous statistical testing, including the use of standard confidence intervals and more sophisticated methods like bootstrap analysis, which offers more accurate confidence intervals. Additionally, the incorporation of random effects helps to address unobserved heterogeneity across distributors, making TCB a robust tool for detailed and nuanced analysis in cost benchmarking studies. This comprehensive approach helps utilities and regulators to better understand cost structures and efficiency patterns, facilitating more informed decision-making in the energy sector.

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[88] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, Ontario Energy Board, November 21, 2013, Appendix A, page XII.

[89] For an illustration, see Dimitropoulos and Yatchew (2017).

[90] Many of these critiques apply to TFP and to other benchmarking approaches.

Advantages and Disadvantages of Total Cost Benchmarking	
Advantages	Disadvantages
* Attribution of cost effects to specific factors	* Requires extensive, high-quality consistent data
* Separate identification of scale, scope, and technology effects	* May be technically complex for non-experts
* Standard statistical techniques	* Results sensitive to modeling assumptions
* Basis for estimating output weights for TFP	* May oversimplify distribution system complexities
* Flexible model structure	* Limited focus on service quality and customer satisfaction
* Statistical testing capabilities	* May not account for regional variations
* Incorporation of random effects	

TCB has provided a very useful tool for the regulation of Ontario distributing utilities. The presence of a large number of utilities permits high quality statistical analysis. The standardization of data and, importantly, the systematic development of capital data has been critical to enhancing the validity of this tool. From the perspective of economic theory, it is superior to TFP approaches because it allows for the differentiation of business and operating conditions and can distinguish between efficiency improvement due to technological innovation and the benefits of scale economies. Some may argue that it is technically difficult to understand for non-specialists. This is not a dispositive argument against their use. A transparent regulatory environment, where stakeholders have access to the data and models, allowing them to reproduce and test the results, strengthens the validity of the process.

However, it has been over a decade since the governing model has been estimated. Since then, there have also been significant and material changes in the industry. It would seem that revisiting TCB estimation and considering variations and other approaches would be appropriate.

5. Concluding Comments

a. Technical Sophistication and Regulatory Costs

Electricity distributors can choose from three incentive rate-setting (IR) methodologies for electricity distributors as part of the move towards an outcomes-based approach: Price Cap IR, Custom IR, and Annual IR Index.[91]

- Price Cap IR: Sets base rates for the first year through a cost-of-service process, with adjustments for the following four years based on specific formulas including industry inflation and productivity factors. TCB is used to calibrate the productivity factor and the individual utility stretch factors.

- Custom IR: Establishes rates for five years based on a utility's forecasted costs and sales volumes. It is tailored to each utility's circumstances, with expected productivity gains factored into rate adjustments. Utilities opting for this method must demonstrate strong planning and operational capabilities.

- Annual IR Index: Rates are adjusted annually using a formula similar to Price Cap IR, but without the initial cost of service process. Utilities under this method must apply the highest productivity stretch factor and provide five-year distribution plans every five years. They are also subject to performance reporting through the OEB's Performance Scorecard.

Most utilities, particularly the smaller ones, choose Price Cap IR, in part to avoid the costs of undergoing an extensive regulatory review. This also reduces the regulatory costs for the OEB. Of the 56 rate-regulated electricity distributors, over 50 choose this track. A few utilities, choose instead to proceed with a Custom Incentive Regulation process (Custom IR). Foremost among these are:[92]

- Hydro One Networks Inc. (EB-2017-0049, EB-2021-0110)
- Toronto Hydro-Electric System Limited (EB-2014-0116, EB-2018-0165, EB-2023-0195)
- Hydro Ottawa Limited (EB-2015-0004, EB-2019-0261)

The above-named three utilities, which are in the Custom IR stream, serve more than half of Ontario electricity customers. The remaining 50+ utilities are under Price Cap IR. From the

[91] Handbook for Utility Rate Applications, Ontario Energy Board, October 13, 2016.

[92] PowerStream and Horizon Utilities filed Custom IRs prior to merger into Alectra Utilities Corporation (EB-2013-0166 and EB-2014-0002 respectively). Alectra is an amalgamation of Enersource Hydro, Horizon Utilities, Hydro One Brampton, PowerStream and Guelph Hydro. Alectra serves about 20% of Ontario customers but it has yet to file a Custom IR as an amalgamated utility.

perspective of regulatory costs – both for the regulator and the utility – there are significant efficiencies gleaned from the Price Cap IR stream as there are substantial fixed costs for any utility, large or small, to assembling a Custom IR submission.

Hydro One Networks Inc. (HONI) is uniquely different as it has the distinct obligation of providing service to any customers *not* served by one of the municipal utilities. It is the default distributor. It is distinguished by its vast geographical coverage and a substantial customer base exceeding 1.4 million, or over 25% of Ontario customers. As noted earlier, it is a statistical outlier, making it difficult to quantitatively incorporate it within the TCB model used by the OEB. Instead, in the Custom IR proceedings, HONI submits statistical analyses using approximately 80 U.S. utilities.

Toronto Hydro-Electric System Limited serves about 15% of Ontario customers. The statistical analyses that it submits in Custom IR proceedings incorporate data on U.S. utilities and excludes Ontario distributors. The estimates of relative efficiency differ significantly from results previously obtained under the OEB TCB model. It would be of value to attempt to reconcile these differences. Data from other jurisdictions could also be considered as well as the re-incorporation of some Ontario data.

Custom IR proceedings involve the expenditure of considerable utility, stakeholder and OEB resources and efforts to streamline them may be worth considering. The value and efficacy of the extensive modeling and submission resources need to be balanced against the regulatory costs, the costs of which are ultimately borne by ratepayers.

b. Does Yardstick Competition and Regulation Work?

Although the terms 'yardstick competition' and 'yardstick regulation' are sometimes used interchangeably, for purposes of this discussion we will distinguish between them as follows. Yardstick competition involves comparing the performance of similar entities against each other with the intent of encouraging better performance. Transparent and widely available performance measures can influence the behaviour of stakeholders, customers, policy-makers and investors.[93] Yardstick regulation involves a formalization within the regulatory process through which performance measures are incorporated into the rewards and penalties imposed by the regulator. In the present case, total cost benchmarking is used to compare utility cost performance, after adjusting for differences in business conditions and operating environments. Imperfect as statistical benchmarking may be, it has been a useful device, refined over a number of years through improved data collection and standardization.

[93] Private firms operating in competitive markets routinely compare their performance using a range of metrics against their competition.

In most jurisdictions, data on reliability are systematically collected, and in some instances, reliability performance are incorporated into the incentive regulation mechanism with beneficial impacts on supply continuity and reliability.[94] Activity and program-based benchmarking are also useful tools, enabling utilities to assess their costs in specific areas against each other.

Various studies analyze the design and effectiveness of incentive regulation.[95] Early studies in Britain found improvements in productivity and the quality of service.[96] The preponderance of studies in other countries generally find also significant productivity improvements.[97] A Norwegian study found that the introduction of yardstick competition led to improved productivity relative to a previous simplified RPI-X regulatory regime.[98]

Yardstick competition in the utilities sector has generally proven beneficial by fostering a collegial competitive environment among utilities, thus encouraging efficiency and cost-effectiveness. Properly implemented, yardstick competition can promote innovation. Utilities, driven by the desire to outperform their peers, may be incentivized to invest in new technologies and processes.

Transparency and accountability are also enhanced under yardstick competition. The publication of performance metrics promotes accountability to both regulators and consumers. However, the benefits of yardstick competition are not without challenges. Accurate and fair benchmarking requires reliable data, and differences in regional conditions can complicate comparisons. Despite these challenges, the overall impact of yardstick competition on utilities has been positive, leading to improved efficiency, cost reduction, and service quality across the sector.

c. Summary of Observations and Possible Considerations for the OEB

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[94] See “2. Background”, section “e. Benchmarking in Other Jurisdictions”, subsection “ii. Benchmarking Reliability”.

[95] For a recent review see Brown, D. P., & Sappington, D. E. M. (2023). Designing Incentive Regulation in the Electricity Sector. MIT Center for Energy and Environmental Policy Research.

[96] D. Newbery & Pollitt, M. G. (1997). The restructuring and privatisation of Britain's CEGB—was it worth it? The Journal of Industrial Economics, 45(3), 269-303. Domah, P., & Pollitt, M. G. (2001). The restructuring and privatisation of the electricity distribution and supply businesses in England and Wales: a social cost-benefit analysis. Fiscal Studies, 22(1), 107-146.

[97] See Hellwig, M., Schober, D., & Cabral, L. (2020). Low-powered vs high-powered incentives: Evidence from German electricity networks. International Journal of Industrial Organization, 73, 102587. For a tabulated survey of study results, see Ajayi, V., Anaya, K., & Pollitt, M. (2022). Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain. Energy Economics, 115, Appendix I, Table A2.

[98] Senyonga, L., & Bergland, O. (2018). Impact of high-powered incentive regulations on efficiency and productivity growth of Norwegian electricity utilities. The Energy Journal, 39(5), 231-256.

The report suggests a number of directions which the Board may consider, should it undertake a review of its benchmarking and incentive regulation model:

- **The Total Cost Benchmarking (TCB) Model Should be Re-Estimated Using More Recent Data:** The TCB model, estimated in 2013, uses data for the period 2002-2012 (later updated to included 2013). The existing model should be re-estimated to include data for the years 2014 -2023.

- **Modifications to the TCB Model Should Be Explored:** Possible variations include incorporating nonlinear specifications, particularly for the productivity trend term; using alternate techniques to evaluate the precision of parameter estimates; and, examining sub-periods to assess whether there are shifts (known as structural breaks) in the mechanisms driving costs. Sensitivity analyses should be conducted.

- **The Inclusion of Additional Variables in the TCB Model Should be Considered:** The energy transition is changing distribution cost drivers. These include the proliferation of distributed energy resources and the increasing need for electric vehicle charging stations. Data which quantify these changes could be collected and incorporated within the TCB framework. Variables measuring service quality and reliability should also be considered.

- **Alternative Productivity Estimation Techniques Should be Explored: '**Stochastic frontier analysis' (SFA) and 'data envelopment analysis' (DEA), both of which are used in other jurisdictions, should be explored.

- **Total Factor Productivity (TFP):** The use of TFP within the X factor should be reconsidered. Additional techniques could be assessed, including 'Multilateral Total Factor Productivity', 'Partial Performance Indicators', and 'Activity and Program-Based Benchmarking'.

- **The Use of Data from Other Jurisdictions Could Be Considered.** It may be beneficial to incorporate data from other jurisdictions, either from other provinces, or jurisdictions outside Canada. As noted, the Australian Energy Regulator has used Ontario distributor data for its benchmarking analysis.

- **Systematic Comparisons of Ontario Distributor Productivity Growth to Other Jurisdictions Could be Undertaken.** Such comparisons could offer valuable insights to drive efficiency improvements, align with best practices, and enhance service quality for consumers. This constitutes an informal kind of international yardstick competition.

- **Alternate Approaches to Stretch Factor Assignments Could be Considered.** Currently, stretch factors are assigned based on inter-utility cost comparisons using the TCB model. A 'Global Stretch Factor' (GSF) could be introduced and set for all utilities. Consideration could be given for setting separate Capital and OMA GSF's. In addition, the GSFs could be augmented with individual utility stretch factors informed by TCB and affecting 'return on equity' (ROE) as either a penalty or a reward. The Board may also consider giving some weight to the rate at which each utility has improved relative to its own past.

- **Quality and Reliability of Service Could Be Incorporated into the Incentive Regulation Formula:** For example, the price-cap model might include a term for quality, (sometimes referred to as a 'q-factor') or a quality term could be incorporated into the stretch factor. Performance Incentive Mechanisms (PIMs) could be incorporated in setting individual ROE's to ensure service quality, reliability and performance.

- **Simulation Modeling Could be Considered:** A small number of 'artificial utilities' could be defined with characteristics spanning the range of Ontario distributors that align with the TCB benchmark. Simulation modeling could then be implemented to assess their evolution as government policies and the industry environment change.

Appendix A. Benchmarking Costs and Reliability in Other Jurisdictions

This appendix focuses on benchmarking costs in various European countries, in Australia, the USA and in certain Canadian Provinces. The latter part of the appendix also discusses benchmarking reliability in Europe and Australia.

A.1 Benchmarking Costs

a. Europe[99]

i. Germany

Cost benchmarking in Germany is intended to promote efficiency, transparency, and accountability within the electricity distribution sector. Electricity distribution in Germany is regulated by the Bundesnetzagentur (BNetzA) as well as various state authorities. Jurisdictional boundaries for regulators are delineated by the scale and scope of the network they govern. For example, most small distributors are regulated by a state authority. There are 880 distribution companies operating 1.9 million kilometers of wire with a mix of ownership structures, including private entities and locally governed public utilities. Regulatory cycles, lasting five years, serve as periodic checkpoints to evaluate and adjust the regulatory framework, with the most recent period spanning from 2019 to 2023.

Revenue caps comprise the main regulatory approach. Reviews require separation of non-controllable and controllable costs, the establishment of efficiency benchmarks, adjustments for general inflation, and consideration of the volatility of certain costs.[100]

Efficiency benchmarking is conducted by the BNetzA, and involves a rigorous examination of TOTEX, capital and operational expenditures. The process employs Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA). While incentive regulation schemes can be administratively complex, regulatory load can be balanced through simplified procedures. A paper from BNetzA[101] mentions that "[t]hree quarters of DSOs opt for the

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[99] An important source is the Report on Regulatory Frameworks for European Energy Networks 2023 produced by the Council of European Energy Regulators (CEER).

[100] Departing from the conventional approach of utilizing the Weighted Average Cost of Capital (WACC), the rate of return on equity combines a nominal risk-free rate with a risk premium, factoring in corporate taxes to arrive at a comprehensive figure.

[101] Bundesnetzagentur (January 18, 2024). Key elements paper. Retrieved from https://www.bundesnetzagentur.de/EN/RulingChambers/GBK/KeyElementsPaper.pdf?__blob=publicationFile&v=4.

‘simplified procedure’, which involves a cost examination but no participation in efficiency benchmarking” (p. 12).

Furthermore, the revenue cap framework incorporates a dynamic sectoral productivity factor, providing an additional layer of flexibility to accommodate changing market conditions and technological advancements. Operators demonstrating superior performance, either through exceeding efficiency benchmarks or maintaining exceptional service quality, may be rewarded with enhanced revenue allowances or other incentives. Conversely, operators falling short of regulatory expectations may face penalties or heightened regulatory scrutiny, for example by requiring additional data and explanations or justifications.

The regulatory framework allows for adjustments to the revenue cap to accommodate capital investments in post-reference years, ensuring that operators have the necessary resources to modernize and expand the network in line with evolving consumer needs and technological advancements.

ii. France

In France, the Commission de Régulation de l’Énergie (CRE) is the independent authority responsible for the regulation of electricity and gas markets. CRE is in charge of setting up access rules and tariffs for the utilization of electricity (and gas) grids. There are 143 electricity distribution system operators (DSOs) in France of various sizes. Distribution is dominated by Enedis, which operates 95% of the electricity distribution network, covering 1.4 million km of lines and serving 35 million customers. Six other DSOs serve more than 100,000 customers (Gérédis, SRD, SER, GEG, URM and EDF SEI) and the remaining DSOs are local companies that serve fewer than 100,000 customers. The current distribution tariffs for RTE (“TURPE-6 HTB”) and Enedis (“TURPE-6 HTA-BT”) entered into force on August 1, 2021, for a period of approximately four years.

During a recent regulatory process, CRE conducted in-depth analyses of projected expenses of French operators, practices in other European countries, and conducted an evaluation of the WACC for electricity infrastructure in France. Operating expenditures and their comparison with those of other European network managers were also examined. At the end of the process, CRE largely kept the previous tariff structure while introducing some improvements regarding incentives relating to CAPEX, quality of service and losses.

CRE collects comprehensive data from distributors on operational and financial performance. These data include information on costs, investments, network reliability, and quality of service indicators. The regulatory authority then analyzes these data to identify trends, assess performance, and evaluate efficiency levels across different distributors.

CRE evaluates the efficiency of distributors by benchmarking their costs and performance indicators against those of their peers. This comparison helps identify distributors that are performing exceptionally well or poorly relative to others.

CRE sets efficiency targets and performance indicators based on the best-performing distributors in the country. Distributors that exceed these targets may be eligible for incentives such as higher revenue allowances or additional flexibility in investment planning. Conversely, distributors that consistently underperform may face penalties or increased regulatory scrutiny.

CRE actively engages with stakeholders, including distributors, consumer associations, and industry representatives throughout the cost benchmarking process. This ensures transparency, accountability, and stakeholder participation in regulatory decision-making. Stakeholder input helps CRE refine its methodologies, set appropriate benchmarks, and address industry concerns.

Cost benchmarking in France also aims to promote innovation and technological advancements within the electricity distribution sector. Distributors are encouraged to invest in smart grid technologies, renewable energy integration, and other innovative solutions to improve efficiency, enhance network reliability, and meet evolving consumer demands.

iii. Great Britain

The Office of Gas and Electricity Markets (OFGEM), regulates electricity and gas in the United Kingdom. There are 14 distribution companies and six distribution system operators overseeing 800,000 km of wire. Cost benchmarking is an essential tool used by OFGEM to assess the performance of electricity distribution utilities and to promote efficiency within the sector.

In 2013, OFGEM implemented the RIIO regulatory framework for transmission and distribution networks. RIIO stands for Revenue = Incentives + Innovation + Outputs, highlighting its focus on incentivizing efficient investment, promoting innovation, and delivering desired outcomes for consumers. Under RIIO, distribution networks are regulated over multi-year periods, typically spanning five to eight years. This longer-term approach provides stability for network owners and operators to plan and invest in infrastructure upgrades and improvements. The RIIO process sets price controls, which determine the amount of revenue network operators are allowed to collect over the regulatory period. It also incorporates performance incentives to encourage network operators to meet or exceed specified targets related to reliability, safety, customer service, and environmental sustainability. Operators that outperform these targets may be rewarded with financial incentives, while underperformance may result in penalties.

The RIIO framework encourages innovation by providing incentives for network operators to invest in new technologies and practices that improve the efficiency and effectiveness of the energy network. This includes initiatives to enhance grid flexibility, integrate renewable energy sources, and implement smart grid solutions. OFGEM emphasizes consumer engagement and accountability by requiring network operators to consult with stakeholders, including consumer groups, throughout the regulatory process. Operators are also required to publish detailed information on their performance and expenditures to ensure transparency and accountability.

Overall, the RIIO framework aims to strike a balance between providing network operators with necessary incentives, and funding to maintain and develop the energy infrastructure while protecting the interests of consumers. It represents a collaborative effort between regulators, network operators, and other stakeholders to ensure the reliable, safe, and sustainable delivery of energy services to consumers.

In order to implement this regulatory framework, OFGEM regularly conducts cost benchmarking exercises to assess the relative efficiency of distribution system operators. OFGEM collects data from all licensed electricity distribution companies and compares their costs and performance metrics. These data include information on operational expenditure, capital expenditure, network reliability, customer satisfaction, and other key performance indicators. By analyzing the data, OFGEM identifies distributors that have significantly higher or lower costs compared to their peers. Outliers may be indicative of potential inefficiencies or areas where improvements can be made. Such companies may then be subject to further scrutiny to understand the reasons behind their performance.

Benchmarks are based on the performance of the most efficient distributors. OFGEM uses the results of cost benchmarking exercises to set price controls and incentives. Distributors that perform better than the benchmarks may be rewarded with higher revenue allowances or financial incentives, while those that perform below expectations may face penalties or tighter regulatory controls.

iv. Denmark

The Danish Utility Regulator (DUR) is an independent authority, entrusted with the oversight of electricity, natural gas, and district heating grid companies in Denmark. Subsequent to the introduction in 2018 of a revenue cap model, the DUR has embarked on a comprehensive approach to regulatory governance, seeking to promote efficiency, reliability, and sustainability within the energy sector.

Under this regulatory framework, which has a five-year regulatory cycle, revenue caps are assigned, drawing from a synthesis of cost considerations, permissible returns, and efficiency mandates. The cost ceiling is grounded in the average of actual costs incurred during the preceding regulatory period, ensuring a prudent balance between operational exigencies and fiscal prudence.

Permissible returns, based on regulatory assets and a rate of return, are part of the revenue cap structure. The regulator uses the weighted average cost of capital (WACC), and returns are subject to adjustments reflective of inflationary pressures and the specific operational context of individual distribution system operators. Notably, adjustments are wielded as a lever to enforce accountability, with deteriorations in service quality, such as an upsurge in outage incidents, precipitating commensurate reductions in rates of return and revenue caps. Efficiency calibration is underpinned by national productivity benchmarks and bespoke DSO-specific targets. This is best explained in a paper by Rasmussen (2023), where "The first component is a general cumulative efficiency requirement, introduced for the first time in the 2018 regulatory framework. This requirement mirrors the productivity increases observed in a comparable Danish industry subject to competition during a given year (Forsyningstilsynet 2019a, 2020a, 2021a). The second component is an individual efficiency requirement, which quantifies the additional catching-up potential for lesser cost efficient DSOs. The rationale behind combining these two requirements is grounded in the fact that productivity and efficiency levels may differ among DSOs due to the absence of competition" (p. 2).

These efficiency targets underscore the regulatory ethos, driving DSOs to continually refine operational efficiencies and promote cost optimization. Companies deemed to exhibit excessive cost burdens face heightened efficiency requirements, as the regulator is committed to fostering a culture of operational excellence and fiscal prudence.

The Regulatory Asset Base (RAB) is stratified into forward-looking and historical domains, each endowed with its distinct rate of return regime. Assets commissioned post-January 2018 are vested within the forward-looking RAB, with returns tethered to the prevailing WACC. Conversely, the historical asset base adheres to former definitions and calibration of rates of return, ensuring continuity and coherence within the regulatory framework.

In a bid to cultivate equity and parity across the energy landscape, an 'availability' tariff has been instituted, mandating that distributed energy resources, including solar photovoltaic installations, bear a proportionate share of grid costs. While smaller producers are subject to a fixed tariff, larger counterparts undergo an individualized tariff setting process, fostering more equitable distribution of costs across the energy ecosystem.

However, notwithstanding the overarching objectives of the revenue cap model, certain inherent limitations and unintended consequences have emerged. The model's neutrality between operating expenditures (OPEX) and capital expenditures (CAPEX) fails to adequately incentivize service flexibility, potentially impeding the agility and responsiveness of grid operators. Moreover, the efficiency requirements, while laudable in principle, introduce distortions by underemphasizing investments in physical infrastructure essential for bolstering service quality and reliability. As such, there is a risk of service quality degradation, warranting nuanced recalibration and iterative refinement of the regulatory framework in the ensuing years.

v. Netherlands

The Authority for Consumers and Markets (ACM) serves as the regulatory body overseeing the operations of electricity and gas distribution system operators in the Netherlands, where a total of six publicly owned electricity and gas DSOs operate under its purview. At the heart of the regulatory framework lies an incentive-based regime, characterized by a revenue cap approach, designed to ensure efficiency and accountability.

Within this framework, regulatory periods, spanning three to five years, are established, with the current cycle spanning 2022 to 2026. The ACM initiates the process by setting the initial allowed revenue to align with the anticipated efficient costs.

The X-factor, also known as the efficiency factor, is a key component of the regulatory framework. The ACM determines the X-factor through a structured process that involves forecasting future cost trends and setting targets for efficiency improvements. Overall, the determination of the X-factor involves a rigorous and data-driven process aimed at incentivizing distribution companies to improve efficiency, reduce costs, and deliver value to consumers while ensuring the stability and reliability of the energy supply. The determination of the X-factor follows these steps:

- The ACM conducts detailed analyses and projections to forecast future cost trends in electricity (and gas) distribution. This involves examining factors such as inflation rates, labour costs, energy prices, technology advancements, and other relevant economic indicators that may impact the operating costs of distribution companies over the regulatory period.

- Based on the forecasted cost trends and other considerations, the ACM sets efficiency targets for distribution companies. These targets represent the desired level of cost reduction or efficiency improvement that companies are expected to achieve over the regulatory period.

- Under the revenue cap framework, the X-factor is calculated as the difference between the forecasted cost trends and the efficiency targets set by the ACM. If the forecasted cost trends exceed the efficiency targets, the X-factor is negative, indicating that distribution companies face revenue reductions compared to their initial allowed revenue. Conversely, if the forecasted cost trends are lower than the efficiency targets, the X-factor is positive, allowing distribution companies to increase their revenue. The X-factor is equal to the annual change in revenue, hence it is a price differential, not a traditional 'efficiency target.' These efficiency targets are determined by a benchmarking model using a data set extending into the past, starting in 2009. Hence, the efficiency targets are informed by past performance.

- The X-factor is reviewed and adjusted periodically to ensure that it remains aligned with changing market conditions, technological developments, and regulatory objectives. The ACM may revise the X-factor based on new data, stakeholder feedback, or changes in policy priorities to ensure that it continues to incentivize efficiency improvements and promotes the long-term sustainability of the electricity (and gas) distribution sector.

To establish the X-factor, the ACM employs several benchmarking methods including total factor productivity, data envelopment analysis and stochastic frontier estimation. Statistical modeling combining cross-section and time-data (panel-data analysis) is also conducted. Overall, the ACM utilizes a combination of these benchmarking techniques to assess the costs and performance of distribution companies, enabling it to identify areas for improvement, set regulatory targets, and promote efficiency in the electricity and gas distribution sector in the Netherlands.

As the regulatory period progresses, adjustments to revenues are made using the ‘X-factor’, unique to each DSO. Annual revenue gradually transitions from the initial to the final figure, with the X-factor dictating the yearly change.

In addition to the X-factor, electricity DSOs are subject to a quality incentive, denoted by the ‘q-factor’. This approach takes into account factors such as service reliability, customer satisfaction, and network performance. DSOs exceeding the average performance in terms of outage duration or frequency are awarded a positive q-factor, augmenting their allowed revenues. Conversely, subpar performance invokes a negative q-factor, resulting in reduced revenue allowances.

The combined effect of the X and q-factors shapes the cumulative impact on permitted revenues, ensuring a balanced approach to incentivizing efficiency and service quality.

A pivotal component of the regulatory framework is the assessment of the ‘Regulatory Asset Base’ using a TOTEX approach. Operating expenses (OPEX) are submitted by network operators, while capital expenditures (CAPEX), encompassing return on investment (ROI) and depreciation, are calculated by the ACM based on operator data. Depreciation periods, ranging from 5 to 55 years, are assigned based on the nature of investments, while the rate of return is derived using a real-plus weighted average cost of capital (WACC) method, adjusting the nominal WACC for inflation.

Underpinning the regulatory cost base is an assessment of static efficiency, comparing the unit costs of each DSO with estimates of efficient unit costs. DSOs operating below the efficiency threshold stand to realize additional returns, with provisions for adjustments to account for disparities in cost types or regional variations.

The regulatory framework attempts to foster an environment wherein DSOs are incentivized to operate efficiently, maintain service quality, and align with industry best practices, ultimately promoting consumer welfare and industry sustainability.

vi. Norway

Norwegian distributors are regulated by 'NVE-RME', the Norwegian Energy Regulatory Authority. There are over 100 DSO network operators. Tariffs based on the allowed revenue equation:

$$AR_t = RC_t + PT_t + TC_t + R\&D_t - CENS_t + TL_t$$

where AR_t represents allowed revenue at time t, RC_t is the revenue cap, PT_t are property taxes, TC_t are tariff costs to other regulated networks, $R\&D_t$ are research and development costs, $CENS_t$ is the cost of energy *not* supplied, and TL_t represents the time lag of capital recovery.

Distribution system operators (DSO's) are locally owned primarily by municipalities and fall under revenue cap regulation. This system has evolved over time, beginning with rate-of-return regulation in the first regulatory period (1993-1996). This was later replaced by a revenue cap regulation system. Data Envelopment Analysis is used to determine company-specific and more general efficiency targets.

By the second regulatory period (1997-2001), NVE-RME had replaced this RoR system with a revenue cap model utilizing a cost base based on the DSO's own historical costs. The regulatory RoR was fixed at 8.3%, and the cost base was adjusted yearly to calculate revenue caps. Revenue caps were increased by inflation and partially offset an efficiency X-factor. Initially, this efficiency target was between 0 and 3%, with revenue caps being adjusted for new investments deducted from growth in distributed electricity. Quality of service regulation was instituted in 2001 to avoid distributors from benefitting in incentives to reduce cost by reducing service quality; or failing to make necessary infrastructural investments. Minor adjustments were made in the third regulatory period (2002-2006), such as updating the cost base and making minor changes in benchmarking models. There remained a time delay between cost and revenue changes.

In the fourth regulatory period (2007-2012), the traditional CPI-X model was replaced with a hybrid version. Each DSO's share of the revenue cap was decided by a combination of the DSO's own costs (cost-plus) and a 'cost norm'. The cost norm was determined by comparing to similar DSO's, a version of yardstick competition. The fifth regulatory period (2013-2018) made minor changes, mainly removing previously existing disincentives for mergers and acquisitions, and instituting incentives for research and development. The 'number of outputs in DEA was reduced and the method for adjusting Z-factors was revised'.

As mentioned earlier, under the revenue-cap system of regulation in Norway, revenue caps are set annually, providing incentive for investments. After 2023, the formula for 40% cost recovery and 60% cost norm resulting from benchmarking models is adjusted to 30% cost recovery and 70% cost norm.

The Norwegian regulator implements two separate efficiency assessment models constituting a multi-stage procedure. In the first stage DEA is used to compare the efficiency of distributors. A Z-factor correction adjusts scores for differences in environmental factors. A company exhibiting average efficiency receives a rate of return equal to interest specified by the NVE-RME. There are separate models for local and regional distributions.

vii. Sweden

The Energy Markets Inspectorate (Ei) regulates electricity distribution system operators in Sweden. Over the years, Sweden has experienced major consolidation in the electricity distribution sector. In the late 1950s, there were over 1,500 companies, but today, the number has declined to 168 electricity distributors. There is a broad range of distributor sizes, the smallest serving less than 100 customers, the largest about 900,000. Historically, Sweden embraced various regulatory approaches, including fictive reference networks and variants of performance-based regulation, often for just one-year periods. Since 2012, the regulatory landscape has undergone a transformative shift towards ex-ante revenue caps, extending over a period of four years.

The determination of revenue caps is a meticulous process, drawing upon the Total Expenditure (TOTEX) methodology and subject to annual adjustments guided by efficiency targets. Productivity requirements primarily target controllable OPEX, with the Regulatory Asset Base assessed for CAPEX based on replacement values for existing assets. Rate of return calculations use the WACC methodology. Incentive norms, tailored to ensure supply security, are based on a blend of metrics such as average interruption time, interruption frequency, and customer experience, further buttressed by benchmarking among DSOs.

Efficiency benchmarking, underpinned by DEA models, incorporates outputs such as customer counts, electricity delivery metrics, and network station parameters. Controllable OPEX calculations are based on four years of historical data, while CAPEX considerations are based on the first year of the regulatory period.

The cost efficiency requirement is based on controllable OPEX, with maximal reductions in revenue caps not exceeding 7.5% and minimal reductions at 1%. Transmission networks have experienced significant congestion, leading regulators to incentivize investments in demand response flexibility services. The objective is to balance the need for traditional grid investments against flexible response by customers at the distribution level.

viii. Spain[102]

Electricity distribution in Spain is regulated by the Comisión Nacional de los Mercados y la Competencia (CNMC) across all jurisdictions. Regulatory jurisdiction was recently transferred to CNMC under Royal Decree Law 1/2019. As a result, the CNMC has powers to set revenues from 2020 onwards and tariffs starting from 2020/21. The Spanish distribution market is dominated by five large distribution system operators (DSOs) which make up roughly 90% of system revenues and 328 small DSOs which serve less than 100,000 clients.

The CNMC uses an incentive regulation system. The regulatory cycle is renewed every six years. The current regulatory cycle is 2020-25. Under renewal, the base year for the next regulatory period is set to the next regulatory period minus two years. There are a key set of elements used by CNMC to determine the revenue cap for DSOs. DSOs receive renumeration for capital expenditures (CAPEX), operations & management expenditures (OPEX), other regulated tasks with reference values, regulatory asset base (RAB), rate-of-return (RoR), regulatory lifetime of assets, number of clients, and incentives/penalties. The subsequent paragraphs provide a detailed breakdown of these components.

The Regulatory Asset Base (RAB) is annually adjusted by adding new investments and subtracting depreciation, excluding assets under construction, working capital, subsidies, and third-party financed assets. Once assets complete their regulatory life, they are removed from the RAB. Newly commissioned assets begin generating revenue two years post-commissioning, with adjustments made using a fixed factor of 1.5 for Distribution System Operators (DSOs). Depreciation of the RAB is managed through straight-line depreciation over 40 years for most assets and 12 years for control centers.

The net RAB pending to recover is multiplied by the RoR, calculated using the Weighted Average Cost of Capital (WACC) for the 2020-25 regulatory cycle. The Capital Asset Pricing Model (CAPM) is used to determine the RoR on equity, incorporating the ten-year Spanish government bond as the risk-free rate, the average beta from a utilities peer group, the European market risk premium from the Dimson, Marsh, and Staunton report, and the cost of debt based on the average of the interest rate swaps and credit default swaps (CDS) of the peer group utilities. In the absence of CDS data for a company, debt bonds with maturity between 8-12 years are used. The debt-to-equity ratio is maintained at the optimal regulatory gearing ratio of 50%, aligned with peer group values.

DSOs receive an Operations and Maintenance (O&M) allowance within a term called 'COMGES', which includes OPEX and a small portion of non-electric asset investments. The

[102] Sources: CEER, A. (2023). Report on Regulatory Frameworks for European Energy Networks 2022. Incentive Regulation for Electricity DSOs (Report on Regulatory Frameworks for European Energy Networks 2022). Núñez, F., Arcos-Vargas, A., & Villa, G. (2020). Efficiency benchmarking and remuneration of Spanish electricity distribution companies. Utilities Policy, 67, 101127.

COMGES is periodically adjusted within the RP based on a ratio that links it to investments in electric assets with reference values, along with an efficiency factor that reflects the company's ability to manage these costs effectively.

With respect to CNMC's incentives for the regulatory lifetime of assets, assets that have exceeded their regulatory lifetime receive higher OPEX reference values to encourage continued operation. The increase in these values is structured as follows: 30% for the first five years, 30%-35% for the next five years, and 35%-45% for years 10 to 15. Beyond 15 years, the increment continues at 3% annually until it reaches a maximum of 100%.

Regarding other regulated tasks with reference values, DSOs are remunerated by CNMC for other regulated tasks such as metering, assisting with client electricity contracts, handling client calls, grid planning, and covering overhead costs. The revenue for each task is based on a reference value multiplied by the number of clients, with different reference values set for various client ranges. DSOs are encouraged to perform these tasks at costs lower than the reference values, retaining any cost savings. Additionally, a bonus term rewards DSOs based on their performance relative to an efficient company in the previous regulatory period.

Lastly, the CNMC incentivizes DSOs to reduce grid loss and improve supply quality. There is also an incentive for fraud detection applied in 2020 and 2021. This was then integrated into the incentive regulatory framework to reduce grid loss.

ix. Italy[103]

In Italy, all energy infrastructure and utility companies are regulated under the Regulatory Authority for Energy, Networks and the Environment (ARERA), which was established in 1995 with the aim to promote competition in the electricity generation sector and ensure efficiency and higher quality of services. The Italian energy sector has largely been fully open to private investors and competition since 2007. There are about 126 Distribution System Operators (DSOs) that cover a network length of 1,276,000 km in the country, mainly private and local public ownership. It is worth noting that the historic monopoly player in the Italian electricity sector, Enel Distribuzione, still controls about 80% of the Italian electricity distribution sector even after over 20 years of competition. There has been an incentive-based mechanism applied to these DSOs since 2002, aimed at increasing efficiency in the sector. This is broken down into input-based incentives, aimed at stimulative productivity efficiency, and output-based incentives aimed at ensuring adequate service quality.

[103] Sources: Annual Report on The State Of Services And Regulatory Activities Carried Out During 2022, Summary 2023, ARERA, https://www.arera.it/fileadmin/EN/publications/annual_report/WEB_SINTESI_2023_ING.pdf. CEER, A. (2023). Report on Regulatory Frameworks for European Energy Networks 2022, https://www.ceer.eu/wp-content/uploads/2024/04/Regulatory-Frameworks-Report-2022-main-report.pdf. Soroush, G., Cambini, C., Jamasb, T., & Llorca, M. (2021). Network utilities performance and institutional quality: Evidence from the Italian electricity sector. Energy economics, 96, 105177.

The productivity efficiency measures in Italy are based on a price cap mechanism applied to operational expenditures. The regulator requires that operational expenditure decreases annually by a designated efficiency factor X. Cost of capital is set with a fixed rate of return, estimated with a Weighted Average Cost of Capital (WACC) methodology. It is important to note, the regulator allows depreciation and cost of capital be passed directly to consumers. This model is adjusted every 4 years, current period being 2024-2027.

Output-based incentives focus on the continuity of supply, or service disruptions in different service regions. The regulator requires DSOs to measure a System Average Interruption Duration Index (SAIDI), calculating a weighted average of consumers affected by disruptions for given DSOs. This is measured geographically in the over 300 territorial districts of Italy. Importantly, the regulator sets a performance target, called the national standard, for a given set of these districts. The districts are grouped together by population density, thus higher density areas are required to provide higher quality of service as measured by SAIDI. The regulator sets a stricter target, i.e., allowed deviation from the national standard for a given group of districts, each subsequent year and allots a penalty or bonus for falling short or exceeding the target, respectively. The aim being to incentivize convergence in service quality among similar districts within Italy. This regulation has been in place since 2004.

b. Australia

The Australian Energy Regulator (AER) oversees the electricity market, with the objective of ensuring that consumers receive reliable and affordable electricity services. One of its key functions is to conduct cost benchmarking exercises for electricity distribution utilities. The AER regulates 13 distributors,[104] ranging in size from 200,000 to 1.8 million customer, comparing their costs and performance of different utilities to identify areas of inefficiency and promote efficiency. The results are published in Annual Benchmarking Reports.[105]

The AER collects extensive data from electricity distribution utilities regarding their operational and financial performance. These data include information on operating expenses, capital investments, network reliability, customer satisfaction, and other key performance indicators. The regulator then analyzes the data to assess the relative efficiency and performance of different utilities.

[104] The AER does not regulate two major distributors operating in Western Australia: Western Power and Horizon Power. Western Power primarily serves metropolitan and suburban areas, while Horizon Power focuses on more remote and rural communities, including towns and settlements across Western Australia's vast and sparsely populated regions. These companies are regulated by the Economic Regulation Authority, an independent statutory authority of the State of Western Australia.

[105] See, for example, Australian Energy Regulator, Annual Benchmarking Report, Electricity Distribution Network Service Providers, November 2023. See also https://www.aer.gov.au/industry/registers/resources/reviews.

Cost benchmarking involves comparing the performance of electricity distribution utilities against each other. The AER evaluates factors such as operating costs per customer, network reliability, and customer service levels to identify utilities that may be operating inefficiently or have room for improvement. By comparing performance metrics, the AER can identify best practices and areas where utilities can make operational improvements.

Notably, as part of the benchmarking process, modeling has incorporated data on over 30 Ontario distributors serving 20,000 or more customers. Data on New Zealand distributors have also been incorporated.[106]

The AER relies on four main approaches to assess productivity: total factor productivity (TFP), multilateral total factor productivity (MTFP),[107] described above, partial performance indicators (PPI) and econometric OPEX cost function models. Output indices include energy throughput, maximum demand, number of customers and circuit length. Customer outages are incorporated as a *negative* output. Input indices include OPEX, overhead sub-transmission lines, overhead distribution lines, underground sub-transmission lines, underground distribution lines, transformers and other capital.

Based on the results of cost benchmarking, the AER sets efficiency targets and performance standards. Utilities that exceed these targets may be rewarded with financial incentives or greater flexibility in pricing decisions. Conversely, utilities that underperform may face penalties or tighter regulatory controls. These incentives are intended to encourage utilities to improve efficiency and provide better services to consumers.

The AER actively engages with stakeholders, including electricity distribution utilities, consumer groups, and industry associations, throughout the cost benchmarking process. Stakeholder input is solicited to ensure that the benchmarking methodologies are transparent, fair, and reflect the interests of all parties involved. This engagement helps build trust and credibility in the regulatory process.

Cost benchmarking encourages innovation within the electricity distribution sector. Utilities are incentivized to adopt new technologies and practices that improve efficiency and reduce

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[106] Addresses shortcomings of using SFATLG (stochastic frontier analysis + translog) model when estimating total output elasticity. Monotonicity violations occur (i.e., elasticities of the wrong sign). There could be a lower standard used for monotonicity, if an estimated elasticity of OPEX is negative and significantly different from zero. Using this lower standard for monotonicity allows many more observations to be used (most violations are not statistically significant from zero). Using 2023 data, there is an unreasonably low total output elasticity estimate for DNSPs using SFATLG model. It is also proposed to add an Australian DNSP time trend (interaction between main time trend and Australian jurisdiction indicator). This new time trend is statistically significant in the short run and long run regressions and leads to more reasonable estimations as well as slightly improving the monotonicity violation frequency.

[107] See 3. Methodologies for Assessing Productivity, part e. Multilateral Total Factor Productivity.

costs. This could include investments in smart grid technologies, renewable energy integration, and demand response programs.

c. USA[108]

The evolution of Performance-Based Regulation (PBR) in the US electricity sector has been slow, both in terms of adoption and recent expansions, particularly regarding electricity distribution. However, since early 2000, PBR has gradually been integrated into electricity distribution across various states, notably influenced by shifts in the electric power industry away from vertically integrated structures to structures that separate generation, transmission, and distribution. After 2015, PBR plans ramped up significantly due to the expanding role of distribution companies.

Indeed, the need to support aggressive renewable integration, grid enhancements, and electric vehicle infrastructure developments has necessitated exploring PBR mechanisms that incentivize utilities to meet new obligations efficiently, given that traditional cost pass-through models did not incentivize innovation or efficiency. These new responsibilities and the associated regulatory complexities have led to a growing interest in implementing various PBR mechanisms, reflecting the need for a more nuanced regulatory approach combining PBR and Cost of Service Regulation (COSR) elements.

In the US, Performance-Based Regulation (PBR) for electric distribution utilities is conceptualized as a set of "building blocks" that can be individually adopted or integrated into a comprehensive regulatory package. Typically, these elements are adopted sequentially by state regulators and utilities. While COSR remains foundational in most states, about a dozen states are currently implementing or planning comprehensive PBR mechanisms, which would serve a similar role to the Great Britain regulation scheme. In total, 39 states are subject to some form of incentive regulation. Still, to this day, Great Britain has more advanced PBR practices under the RPI-X and RIIO frameworks, which have significantly influenced the country’s transmission and distribution sectors but have yet to impact US practices similarly.

Key components or building blocks include Performance Incentive Mechanisms (PIMs), revenue decoupling mechanisms, Multi-Year Rate Plans (MYRP), and performance incentives for new initiatives and pilot programs.

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[108] Paul L. Joskow (2024), “The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States” MIT CEEPR Working Paper 2024-01, January 2024, https://ceepr.mit.edu/wp-content/uploads/2024/01/MIT-CEEPR-WP-2024-01.pdf and https://ceepr.mit.edu/wp-content/uploads/2024/01/MIT-CEEPR-WP-2024-01-Brief.pdf. Hawaii Public Utilities Commission (HPUC). (2020). “Instituting a Proceeding To Investigate Performance-Based Regulation.” https://puc.hawaii.gov/wp-content/uploads/2020/12/2018-0088.PBR_.Phase-2-DO.Final_.mk_.12-22-2020.E-FILED.pdf.

Initially linked to energy efficiency programs, PIMs have evolved to include performance metrics such as customer service, reliability, employee safety, and efficiency. More recently, PIMs have expanded to address the broader regulatory and policy landscape, incorporating targets for distributed generation, electric vehicle (EV) storage facilities, time-of-use pricing, and environmental metrics like greenhouse gas emissions reductions. Incentive structures vary, with some states implementing financial penalties or rewards based on performance while others rely on reputational incentives through public scorecards.

Revenue decoupling mechanisms adjust utility revenues to prevent financial disincentives associated with reduced electricity sales due to efficiency programs or other factors that lower demand. Around 30 states have adopted similar mechanisms, known as Lost Revenue Adjustment Mechanisms (LRAM) or general revenue decoupling, to stabilize utility revenues and encourage the adoption of programs that may otherwise negatively impact utility financials.

MYRPs adjust prices or revenues based on external indices between general rate cases. These plans are akin to dynamic price adjustment mechanisms with predetermined terms (typically 3-5 years), after which prices are reset through traditional COSR processes.

MYRPs can be broadly categorized into two types:

- MYRPs aligned with PBR: These plans adjust prices or revenues based on external indices and often include profit-sharing or sliding scale arrangements to manage uncertainties and encourage cost efficiency.

- Dynamic Formula Rate Plans: In contrast, these are essentially cost-plus mechanisms that adjust rates based on the utility's actual incurred costs, ensuring earnings within a predetermined rate of return. These plans are less aligned with PBR principles, as they often lead to poor efficiency incentives by automatically passing costs to consumers without rigorous regulatory review.

These plans have evolved, incorporating various modifications to address specific regulatory needs and challenges. The California Commission (CPUC), the New York Commission (NYPSC) and other states like Maine, Massachusetts, Hawaii, Minnesota, Vermont, Rhode Island, and Maryland have adopted or are considering MYRPs that incorporate aspects of PBR, aiming to blend regulatory predictability with incentives for efficiency and service quality improvement. In summary, PBR in the US is becoming increasingly sophisticated, with states like Massachusetts implementing complex deadband, penalty ranges, and financial penalty formulas with significant implications for utilities based on their performance relative to established benchmarks.

Finally, performance incentives for new initiatives and pilot programs encourage utilities to adopt innovative practices and technologies that align with state and federal policy goals, such as decarbonization and grid modernization. Key examples include:

- New York's Reforming Energy Vision (REV): This framework positions utilities as platforms for third-party service competition, offering financial incentives to utilities when they select third-party providers for services. This model aims to foster an environment where revenues from third-party services can grow, supporting state climate goals and innovation in the energy sector.

- Brooklyn-Queens Demand Management Program: Initiated by ConEdison, this program focuses on demand management as an alternative to costly infrastructure upgrades, allowing the utility to capitalize and earn returns on the investments over a decade.

- Non-Wires Alternative Requirement in California: Utilities hosting projects can charge a fee for using non-wires alternatives, providing a financial incentive to adopt technologies that may reduce traditional utility revenues but offer system benefits.

- Long-Term Renewable Energy Contracts in Massachusetts: Utilities manage competitive solicitations for long-term contracts with renewable energy suppliers, receiving a fee for their contractual obligations, which helps mitigate the financial risks associated with long-term price fluctuations in energy markets.

- Electric Vehicle Battery Utilization Programs in California: Special funding supports pilot programs to explore using electric vehicle batteries as power sources during blackouts and for supplying electricity back to the grid.

Hawaii is an example of a state that recently implemented a comprehensive PBR plan. Hawaii's Public Utilities Commission (HPUC) multi-year PBR plan, which started in June 2021, is designed to align with Hawaii's ambitious goal of generating 100% of its electricity from renewable sources by 2045. Hawaii's approach includes all the essential elements of PBR to regulate its four vertically integrated electric utilities.

It includes a MYRP in the form of an Annual Revenue Adjustment Formula (ARA) that adjusts revenues based on a combination of an X factor, the Gross Domestic Product Price Index (I factor), a business condition Z factor, and a stretch factor (customer dividend).

Further incentives include PIMs targeting renewable portfolio goals, distributed energy resource (DER) assets, customer engagement, and service quality metrics like SAIDI/SAIFI. Incentives for third-party DER participation and an earnings-sharing mechanism that distributes profits above or below the set rate of return between customers and shareholders are also in place. Finally, the plan also incorporates provisions for handling uncertain future costs, such as the Exceptional Project Recovery Mechanism (EPRM) for extraordinary projects.

d. Canada

i. Alberta[109]

Since 2012, the Alberta Utilities Commission (AUC) has introduced a performance-based regulation (PBR) approach using an I-X (inflation minus productivity) index price cap plan to benchmark four electricity distributors (ATCO Electric, FortisAlberta, ENMAX Power Corporation, and EPCOR Distribution and Transmission) and the two gas distributors. The AUC 2024-2028 performance regulation plan (PBR3) significantly changes the framework.[110]

The AUC has made changes to the I factor. Instead of the Alberta Average Weekly Earnings, this PBR uses the Alberta Fixed Weighted Index (FWI) labour price index, with a labour weight of 60 percent and a non-labour weight of 40 percent. Additionally, the I factor now uses forecasting and a true-up approach instead of a lagged approach. The industry TFP growth, a stretch factor, and benefit-sharing premiums are combined to obtain the X factor.

Various distributors have expressed skepticism about the reliability of TFP growth studies. They argue that these studies, which use historical data, might not reflect more recent and relevant short—and mid-term trends. Dr. Makholm (NERA) noted that the available data fails to capture all utility services, like cybersecurity, which are significant but complex to measure. Instead of calculating a TFP-based factor, he proposed that the AUC rely on externally published inflation indexes, highlighting that few U.S. states still use TFP growth measures.[111] Without introducing undue complexity into the calculation of TFP, these are the shortcomings Activity and Program-based Benchmarking may be useful in correcting.

While acknowledging the limitations of TFP growth studies, the AUC supports their continued use in setting the X factor. This support is contingent upon the assumptions used

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[109] The Alberta Utilities Commission (AUC) established a total factor productivity (TFP) growth factor (X factor) of 0.1 per cent based on industry TFP growth and a stretch factor, prior to the inclusion of benefit-sharing provisions. The Commission also approved an additional benefit-sharing provision in the form of an X factor premium of 0.3 per cent. Except for the calculation for K-bar, the total X factor utilized in PBR3 is 0.4 percent, inclusive of industry-wide TFP growth, a stretch factor, and a benefit-sharing premium. For K-bar calculations, the X factor of 0.1 per cent is used (AUC, 2023).

The AUC based this decision for the Performance-Based Regulation 3 (PBR3) term on TFP growth studies filed by Dr. Lowry, Dr. Meitzen, and Dr. Jeff Makholm. The AUC examines the growth in industry productivity over time, by measuring the mean TFP growth rates for as many utilities in the industry as possible – given data availability. This growth rate is then adjusted by a stretch factor.

[110] Alberta Utilities Commission. (2023). 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, https://efiling-webapi.auc.ab.ca/Document/Get/794425.

[111] NERA Expert Report. AUC Proceeding 566, Exhibit 566-X0080.02, NERA Expert Report, https://www2.auc.ab.ca/h002/Proceeding566/ProceedingDocuments/1a_ID566%20N_0204.pdf

being well-documented, justified, and updated to reflect current conditions. This perspective is echoed by experts such as Dr. Lowry (PEG) and EPCOR's productivity experts, Dr. Meitzen and N. Crowley, who believe that TFP growth studies, despite their limitations, provide a valuable benchmark for utility productivity.[112]

The AUC considered three studies to calculate the TFP growth number:

- Updated from a previous review to include data from 2010 to 2021, the NERA study follows a long-term view, emphasizing consistent methodology without adjustments to the original assumptions used in earlier studies[113].

- Another study, conducted by Dr. Meitzen and N. Crowley for EPCOR, builds upon an earlier framework similar to the NERA study but introduces methodological refinements[114].

- Finally, Dr. Lowry's study for the Consumers' Coalition of Alberta (CCA) uses an independent dataset focusing on around 90 U.S. utilities.[115] It deviates from the other studies' methodologies, primarily based on previous PBR reports' methodologies. Instead, it calculates TFP growth by examining the partial factor productivity of capital and O&M inputs using recent data.

The NERA and Meitzen studies use volumetric output measures (megawatt hours sold). In contrast, the PEG study opts for the number of customers, suggesting different views on what best reflects utility productivity under regulatory caps. The results suggest that more weight on the volumetric output measure results in a lower TFP growth number than using more weight on the number of customers. As such, the TFP growth numbers were updated to use a 50:50 composite output instead of only the volumetric output or the number of customers.[116]

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[112] NERA: Initial TFP Growth: 0.002, Composite output TFP measure: N\A; -Meitzen: Initial TFP Growth: -1.08, Composite output TFP measure: -0.51; PEG: Initial TFP Growth: 0.08, Composite output TFP measure: -0.28

[113] AUC Exhibit 27388-X0182, NERA evidence, https://www2.auc.ab.ca/Proceeding27388/ProceedingDocuments/27388_X0182_Independent%20Evidence%20of%20Dr.%20Jeff%20D.%20Makholm_000218.pdf

[114] AUC Exhibit 27388-X0214, M. Meitzen and N. Crowley evidence for EPCOR, https://www2.auc.ab.ca/Proceeding27388/ProceedingDocuments/27388_X0214_Appendix%20B-1_000248.pdf

[115] AUC Exhibit 27388-X0204, PEG evidence for the CCA, https://www2.auc.ab.ca/Proceeding27388/ProceedingDocuments/27388_X0204.01_CCA%20Evidence%20of%20Pacific%20Economics%20Group%20-%20Power%20Errata%20redline_000742.pdf

[116] "While Dr. Meitzen and N. Crowley commented that a 50:50 weighting of customers and volumes is somewhat arbitrary, they could not calculate the theoretically correct output measure reflecting the actual weights for each company and each year of the study given the practical difficulties of doing so.

Dr. Lowry pointed to the information in an IR response that the average ratio between fixed charges and energy charges across all Alberta distribution utilities is 42:58 and stated an equal weighting of customer and

The stretch factor, a key component of the performance-based regulation plan, acts as a further restraint on the rate increase of prices or revenues. It is designed to enhance efficiency gains by sharing the incremental benefits of productivity with customers right from the start of the PBR term rather than waiting until the end for rebasing. The various parties did not provide specific numbers for the stretch factor. Except for Makholm, all the experts agreed that a stretch factor could be justified. AUC's decision: X factor of 0.4 percent, which includes the TFP growth, the stretch factor (together 0.1 percent), and the X factor premium (0.3 percent).

While some participants argued the stretch factor was no longer necessary, others claimed it could reduce utilities' overearning. Ultimately, the AUC struck a balance and opted for a conservative value, believing that further efficiency gains were possible.

As an alternative to the current methods to calculate the stretch factor, Dr. Lowry (PEG) further proposed econometric models to benchmark non-energy/fuel O&M expenses, capital costs, and total costs for Alberta distribution utilities, controlling for various business conditions. PEG highlighted that their methodology produces more accurate estimates of cost efficiency changes than traditional productivity indexes. However, due to the implausible results for specific utilities, it decided not to base the stretch factor upon this analysis.

In addition to the industry TFP growth and stretch factor, the AUC opted to continue with an earnings-sharing mechanism (ESM) with customers and an additional 0.3 percent X factor premium. There is no sharing with customers if a distributor is below 200 basis points above the approved return on equity (ROE). Between 200 and 400 basis points above ROE, incremental earnings are shared 60 percent to the utility and 40 percent to customers. Above 400 basis points, 80 percent of incremental earnings are shared with customers. Supplemental capital funding mechanisms are also outlined under PBR3 to recover prudent costs and provide incentives regarding capital cost management.

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volume outputs would be preferable in setting the X factor for price cap plans as compared to the entirely volumetric output.

In the Commission's view, the same can be said about using number of customers as the only output measure as is the case in PEG's study. Given that is it very unlikely that the majority of the utilities in PEG's and Dr. Meitzen's studies obtain their revenue entirely from either volumetric or fixed charges, the Commission considers that a composite output measure reflecting a 50:50 weighting of customers and volumes to be a more reasonable assumption for the purposes of this decision as compared to relying entirely on either of those measures. In future PBR proceedings, the Commission will consider evidence on more precise output weightings that are feasible, practical, reasonable and do not result in significant regulatory burden." Alberta Utilities Commission (2023, October 4). 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities (p. 32, 38). https://efiling-webapi.auc.ab.ca/Document/Get/794425.

ii. British Columbia

In British Columbia, the electricity sector is regulated by the British Columbia Utilities Commission (BCUC), which also regulates Natural Gas and all energy related projects in the province. BCUC regulates the rates consumers pay to the electricity providers. The largest electricity provider in British Columbia is BC Hydro, servicing almost 95% of the residents in British Columbia. The second largest provider of electricity is FortisBC, accounting for almost the rest of BC residents although FortisBC mainly provides natural gas services.

The government of British Columbia, BCUC, and BC Hydro began a comprehensive review of electricity regulation in 2019, which is still ongoing. BCUC is considering adopting new incentive-based regulation to impose on BC Hydro and FortisBC. Currently, BCUC employs a Demand Side Management program that tracks costs, Service Plans that track performance metrics, and cost-of-service regulations peg rates to costs.

BCUC and BC Hydro are currently in negotiations to adopt 3-year test periods for rate regulations, regular statistical benchmarking, and Information only models. The details of these proposed regulations are not publicly available.

A.2 Benchmarking Reliability

There are two main reasons for discussing benchmarking of service quality and reliability in this study, the main focus of which is benchmarking costs.

> The first is to assess the possibility of incorporating reliability statistics into the comparative cost analyses. For example, one could include outage frequency and duration statistics in econometric TCB models.
>
> The second is to review how such performance statistics might be used to incentivize improved service performance in an IRM setting. For example, a price-cap model might include an additional term for quality – a q-factor – as is done in some jurisdictions. Or it could be incorporated into the stretch factor.

The OEB mandates systematic reporting of the "Avg. Number of Times that Power to a Customer is Interrupted" and "Avg. Number of Hours that Power to a Customer is Interrupted".[117] These statistics are publicly available in Electricity Utility Scorecards and in consolidated summaries. In 2021 the OEB launched its 'Reliability and Power Quality Review

[117] These include industry standard statistics System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). See Ontario Energy Board, Electricity Reporting & Record Keeping Requirements (RRR), Effective March 8, 2023 https://www.oeb.ca/sites/default/files/RRR-Electricity-20230308.pdf

(RPQR) to assess the “overall reliability performance framework”. To date, reliability statistics have not been used in Total Cost Benchmarking or Activity and Program-based Benchmarking.

In some jurisdictions outside of North America, there is a growing trend to connect reliability standards and incentives to the value of lost load (VoLL). Linking VoLL to penalties for failing to meet reliability targets adds a layer of accountability, incentivizing distributors to prioritize maintaining a stable grid.[118] CEPA provides a background overview of methodologies for calculating VoLL, distinguishing between ‘stated preference’ and ‘revealed preference’ methodologies, what individuals say and what they do[119].

a. Europe

The Council of European Energy Regulators (CEER) and the Energy Community Regulatory Board (ECRB) periodically publishes benchmarking reports on the ‘quality of electricity and gas supply’. The most recent report (2022) includes data on 39 countries. The Report delves into three key elements that determine the quality of electricity supply: its availability and the incentives for its enhancement; the technical features of power grids, such as continuity of supply and voltage quality; and the efficiency and timeliness in addressing customer service requests.

In 19 countries regulatory incentive regimes target continuity of service, mainly at the distribution level. These typically consist of rewards for superior performance and penalties for inferior performance. A number of countries have mechanisms in place to financially compensate electricity customers for service interruptions. Compensation typically applies when interruptions exceed specified thresholds in duration or frequency. Each country's regulations differ, with varying factors like outage duration, voltage levels, and external conditions influencing the rules. In 14 countries, this compensation is automatic, while in others, customers must request it. Notably “Many countries reported improved continuity of supply (a shorter duration or a lower number of interruptions) when incentive

[118] See 7TH CEER-ECRB Benchmarking Report on the Quality of Electricity and Gas Supply 2022, pp. 94-103, available at https://www.ceer.eu/documents/104400/7324389/7th+Benchmarking+Report/15277cb7-3ffe-8498-99bb-6f083e3ceecb.

[119] Cambridge Economic Policy Associates Ltd (2018, July 18). STUDY ON THE ESTIMATION OF THE VALUE OF LOST LOAD OF ELECTRICITY SUPPLY IN EUROPE: ACER/OP/DIR/08/2013/LOT 2/RFS 10: AGENCY FOR THE COOPERATION OF ENERGY REGULATORS. https://www.acer.europa.eu/sites/default/files/documents/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf.

regimes/compensation schemes were implemented, even with indicators that are not regulated."[120]

As noted earlier, the Dutch regulatory authority incorporates a quality incentive (a q-factor) into its revenue cap framework. Distributors which exceed average performance with respect to outage duration or frequency receive a positive q-factor which increases their allowed revenues. Below average performance results in a negative q-factor, reducing allowable revenues.

In Sweden, interruptions are benchmarked by service quality indicators based on historical data, such as AIT (average interruption time) and AIF (average interruption frequency). To incentivize DSOs to deal with service interruptions, regulations mandate compensatory measures for customers enduring outages exceeding twelve hours, with prolonged outages breaching the twenty-four-hour threshold deemed illegal. In Sweden, unlike Ontario, "[t]he indicators [for sustained disruption] are calculated from unplanned outages longer than 3 minutes caused by faults in the local DSOs own grid, overlying or contiguous grid, if not otherwise stated".[121]

In the United Kingdom, distributors have target levels for reliability with concomitant rewards and penalties. Customer interruptions (CI) are quantified by the number of supply interruptions per 100 connected customers in a year. Customer minutes lost (CML) represent the average duration of an interruption in minutes. The incentive rate, determining the reward or penalty is intended to reflect customer willingness to pay for reliability improvements, typically based on the Value of Lost Load (VoLL). Consequently, the reward a distributor earns for surpassing their target or the penalty incurred for failing to meet it, is aligned with the value customers attribute to enhanced service levels. Incentive payments and penalties under the Interruption Incentive Scheme (IIS) is capped to prevent customers from bearing the burden of excessive rewards a distributor might receive due to the incentive structure. Under the current price control regulations, the maximum allowed incentive revenue or penalty for distributors is capped at +1%/-2.5% of return on regulated equity.[122]

b. Australia

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[120] 7TH CEER-ECRB Benchmarking Report on the Quality of Electricity and Gas Supply 2022, Foreword, page 1.

[121] The Swedish Energy Markets Inspectorate (Ei) (2020). Power outage related statistics in Sweden since the early 2000s and evaluation of reliability trends, p.3. https://ei.se/download/18.4ed2158a18722d7df785b73/1680684552868/CIRED-2020-Power-outage-related-statistics-in-Sweden-since-the-early-2000s-and-evaluation-of-reliability-trends.pdf

[122] London Economics International LLC (2023, March 7). Strengthening Utility Accountability for Reliability. Presentation to the Reliability and Power Quality Review ("RPQR") Working Group. Prepared for the Ontario Energy Board. https://engagewithus.oeb.ca/27253/widgets/130945/documents/100524.

The Australian Energy Regulator incentivizes electricity distributors to minimize customer electricity interruptions by setting performance targets and monitoring outcomes. Distributors that surpass the benchmarks may receive financial rewards, while those falling short may face penalties.

As noted earlier, reliability is considered a 'negative output' in the regulator's Multilateral and Total Factor Productivity (TFP) as well as capital Partial Factor Productivity (PFP) analyses. Under the Service Target Performance Incentive Scheme (STPIS), distribution networks are subject to financial incentives or penalties based on a 5-year average for enhancing or declining service reliability.

Appendix B: Distributor and Intervenor Views on Benchmarking

B.1 EB-2010-0379

Beginning in 2010, the OEB embarked on the 4th Generation Incentive Regulation process. In 2012, the Board published its "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach". Following extensive consultations and hearings, the Board filed its decision in "EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, November 21, 2013." Since that time, incentive regulation of distributors has been guided to a large extent by these two documents.

This section summarizes views expressed on behalf of certain distributors in the above process. The Electricity Distributors Association filed evidence on behalf of many of its members. The Coalition of Large Distributors filed evidence on behalf of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc. Also in this section, submissions of certain intervenors have been summarized.

a. Electricity Distributors Association (EDA)

Following the analyses and reports provided by Board consultant,[123] PEG, the EDA presented findings based on two approaches: index-based (TFP) and cost-based (TCB) modeling.[124] Both approaches yielded estimates of productivity growth of -0.8%, (i.e., *negative* estimated productivity growth) indicating significant upward cost pressures in the electricity distribution industry. The exclusion of the two largest distributors (THESL and Hydro One) did not substantially alter the results.

The EDA disagreed with the recommendation by PEG to set the productivity factor at "no lower than zero". Policy priorities such as green energy, conservation and smart grid technologies were expected to continue to put upward pressure on costs.

In addition, PEG recommended stretch factors ranging from 0.0% to 0.6%. The EDA argued that electricity distribution in Ontario had already experienced years of incentive regulation and that stretch factors ranging from -0.3% to +0.3% would be more appropriate. Nor would they be inconsistent with yardstick competition. The EDA evidence also argued that the estimation of relative efficiencies was challenging and prone to misclassification due to minor model

[123] Larry Kaufmann was the principal expert on behalf of PEG.
[124] Adonis Yatchew testified for the EDA.

variations and unresolved data issues. The paper proposed a change to the demarcation lines between efficiency groups to mitigate risks of unfair penalization. The tranche system in PEG's analysis had put a disproportionate number of distributors in the highest stretch factor groups, and very few in the lowest groups. The demarcations, it was argued, placed some distributors with widely different efficiency rankings together. The "distribution with the highest proposed stretch factor has distributors with 'actual minus predicted costs' ranging from 15% to 73%" (p. i). A different system of tranches was proposed with the majority in the center tranche, displaying actual costs between 0% and 15% above predicted costs.

While supportive of the Board's move to a broader inflation measure, concerns remained regarding potential divergence between proposed inflation measures and capital-related cost pressures experienced by distributors. The weighting of the labour price index towards non-union labour appeared unreasonable, suggesting a higher weight for unionized labour.

Peer group analysis, as had been previously proposed, was considered to be contentious and unlikely to contribute productively to assigning distributors to efficiency groups. The EDA supported the Board's decision to set it aside for now.

EDA submissions noted that since 2008, the regulatory process had been improved by the development of detailed Ontario distributor data. Previously, PEG had relied on U.S. distributor data, mainly because of the unavailability of good capital data for Ontario distributors. Total cost benchmarking was now possible. Previously, the alternative of relying on OM&A benchmarking (operations, maintenance, and administration) had been seen to be deficient, mainly because it created incentives for increased capitalization of costs in order to improve OM&A numbers.

The EDA analysis also pointed out that in order to implement TFP benchmarking, it was necessary to import coefficients from the cost model in order to construct weights for the output index. The cost model, it was argued, was simpler and more direct, yet useful as a robustness check. Furthermore, the index model could not discern between scale and productivity aspects. Production scale can be inferred by total customers served, kWh of electricity delivered, and system capacity.

b. Coalition of Large Distributors (CLD)[125]

The testimony filed on behalf of the CLD was generally in agreement with the TFP analysis filed by Board Consultant the Pacific Economics Group. However, it disagreed with the exclusion of outliers, and the exclusion of bad debt expenses on the notion it is unlikely to

[125] Steve Fenrick was the principal expert on behalf of the CLD.

persist into the future. With regards to alternatives to benchmarking, the report argued there should be one econometric benchmarking model ranking distributors according to relative cost performance and followed by assignment to six groups (not five), based on their position in the ranking. The report argued the 0.6% upper bound for the stretch factor should be reduced to 0.5%.

With respect to alternatives to econometric benchmarking, the report proposed a unit cost model (i.e., cost-per-customer) with several business conditions as explanatory variables. The model notably excluded kWh deliveries and included certain customer and service area characteristics, such as percentage of large and general service loads, hourly high winds exceeding 10 knots, percent of single-phase lines, load factor, and percent of lines underground. Unlike the OEB model, the model assumed constant returns to scale.[126] The proponents claimed that his specification was easy to understand with parameter coefficients being unit cost elasticities. The model was neutral to distributor size and did not prejudge efficiency gains through economies of scale. The OEB disagreed with the constant returns to scale assumption.

On the other hand, the Board agreed that wind data could be used in future modeling but found many of the other variables (such as load factor, percentage of single-phase lines) were not statistically significant in the responding PEG report. PEG also included a proxy for age through the "share of customers served that were added over the last 10 years" (p. XIV). The data for the percentage of embedded kW or kWh and a forestation variable was not yet available, and the EDA evidence had already stated concerns about the inclusion of LV and HV adjustments in the benchmarking.

The CLD report also proposed a capital sub-index within the inflation factor. The Board disagreed arguing that inflation calculations should be transparent and easy to understand, and falling within the purview of existing practices.

The CLD report had proposed a 3-factor IPI including a Triangularized Weighted Average of the 'Electric Utility Construction Price Index' (EUCPI) as the capital sub-index, yielding comparable volatility to the GDP Input Price Index for final domestic demand (GDP-IPI FDD) for inflation calculations. The Board disagreed with this due to its volatility.

[126] Ontario Energy Board (2013, November 21). Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors. EB-2010-0379. (p. 21). https://www.oeb.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_Report_of_the_Board_20131121.pdf.

c. Other Intervenor Views

School Energy Coalition (SEC)

Regarding the Board's policies on the incremental capital module (ICM), the SEC presented an analysis and expressed concern over potential rate increases under the current Incentive Regulation (IR) regime of the ICM and how they might carry forward under Price Cap IR. Other distributors have also raised issues regarding the operation of the ICM.

The SEC suggests using average measures of total factor productivity (TFP) growth rather than industry aggregate measures for productivity estimation in the index approach. PEG conducted estimates based on this approach and reported the results in the Supplemental Empirical Analysis report dated June 14, 2013[127].

Furthermore, the SEC proposes an "analog stretch factor formula" for assigning unique stretch factors to each distributor based on their unit cost performance relative to others. Ranking would be done using percentage variation between the unit costs and the median for their peer group. Instead of empirically derived peer groups, the SEC proposed a "crowd-sourcing" process, such that distributors would rank themselves based on similarity to ten other distributors, and the Board staff would revise the lists to ensure comparability between distributors. The risk of having their views not included would mitigate incentives to game the system.

Vulnerable Energy Consumers' Coalition (VECC)

Regarding stretch factor values, the OEB's approach involves assigning stretch factors based on actual costs compared to predicted costs for each DSO. While this approach was generally seen as positive, Vulnerable Energy Consumers' Coalition noted that a large proportion of DSOs were categorized as less efficient. VECC proposed an allocation where most DSOs are assigned to the three central groups of efficiency, resulting in an allocation that more closely resembles a normal distribution.

Regarding data issues, the OEB proposed low voltage (LV) and high voltage (HV) services data adjustments to make the DSOs more comparable. Some participants, such as the VECC, made specific recommendations on what adjustments should be made.

[127] Ontario Energy Board. (2013). EB-2010-0379 PEG Supplemental Empirical Analysis. http://www.ontarioenergyboard.ca/OEB/Documents/EB-2010-0379/PEG_Supplementary_Empirical_Analysis.pdf

Power Workers' Union (PWU)[128]

PWU suggested the use of 'price-dual' Total Factor Productivity (TFP) to assess the reasonableness of index-based TFP analysis. TFP was assessed for sub-intervals within the 2000-2011. To account for the OEB's outcome-based regulatory approach, the following variables, and their impacts on distributors' TFP performance were assessed:

- Impact of line loss performance
- Customer-valued service reliability performance

The PWU evidence also discussed different options for benchmarking such as data envelopment analysis (DEA). Along with some other experts, PWU proposed that reliability performance be incorporated in the OEB's benchmarking.

The data used by the PWU expert differed from the approach conducted by PEG given the incompleteness of capital data across Ontario distributors. The PWU analysis relied upon a sample of 48 distributors that together served more than 70 percent of Ontario distribution customers. In contrast, PEG includes all distributors in its sample.

After conducting the analysis, the expert found a declining trend in TFP during 2000-2011. The sub-interval 2002-2005 differed from the 2006-2011 period with the latter period exhibiting a worsening trend. This may have been in part due to the 'great recession' of 2008-2009.

As a result of these findings, PWU recommended a weighted approach similar to the one used in 1st Generation PBR. In this earlier period, the OEB found contrasting TFP growth rates for sub-intervals. In the RP-1999-0034 decision, the Board assigned 1/3 weight for the first five-year period and 2/3 weight for the second five-year period. The underlying rationale being that recent data are more relevant and indicative of current and future circumstances.

B.2 Distributor Interviews

This section contains summaries of interviews of a select group of utilities, without prejudice. Any inadvertent misstatements or misrepresentations are the fault of the interviewer. A proper canvassing would encompass a comprehensive collection of Ontario distributors.

a. Elexicon

Elexicon, established in 2019 through the merger of Veridian and Whitby, serves approximately 178,000 customers across several regions including Ajax, Belleville, Brock,

[128] Francis Cronin was the principal expert witness for the PWU.

Clarington, Gravenhurst, Pickering, Port Hope, Scugog, Uxbridge, and Whitby. The utility is guided by four strategic pillars: customer centricity, operational excellence, economic development, and strategic investment. Elexicon provides electricity distribution services and also handles billing for water.

The company faces several challenges and considerations that affect its operations and strategic decisions. For instance, differences in the level of service, such as the presence of 24-hour control centers and the need for grid modernization, are not always adequately reflected in cost benchmarking models. This issue is highlighted in the Auditor General's report which points out the low costs associated with smaller utilities.[129]

As cities and regions within Elexicon's service territory grow, capital constraints emerge as a significant concern. There is a risk of infrastructure degradation if investments are not adequately planned and executed. The lumpiness of modernization investments can also distort assessments of efficiency, making it challenging to gauge true operational effectiveness. The incremental capital module, which is seen to be restrictive and typically reserved for discrete projects, further complicates funding for necessary investments. Demographic changes are also a factor, with the Durham region expected to see a 50% increase in population over the next decade and Belleville experiencing rapid growth. These changes necessitate careful planning and adaptation to meet increasing demand and evolving customer needs.

Inflation and the push towards 'net zero' initiatives introduce additional complexities. The competition for specialized labour, materials, and talent is intensifying, which could lead to higher costs and more intricate decision-making processes. Furthermore, cloud technology and cybersecurity are increasingly important, adding to operational costs. Finally, the exploration of non-wires alternatives such as energy storage and demand response present new opportunities and challenges, complicating the decision-making landscape for Elexicon as it navigates its strategic and operational priorities in a changing energy sector.

b. Milton Hydro

The utility currently serves approximately 42,000 customers and has experienced significant improvements in its operational metrics, starting from lower groups with higher stretch factors and progression to the top group with the lowest stretch factor. One of the primary challenges it faces is managing capacity within a rapidly growing environment. Presently, the utility has a capacity of 200 MW, but the potential addition of a data center, would require an additional 350 MW.

The culture within the organization is recognized as a critical element that influences its operations. However, benchmarking the value of human capital poses challenges due to its

[129] Office of the Auditor General of Ontario (2022, November). Value-for-Money Audit: Ontario Energy Board: Electricity Oversight and Consumer Protection.
https://www.auditor.on.ca/en/content/annualreports/arreports/en22/AR_ElectricitySectorOEB_en22.pdf

qualitative nature. There is a strong emphasis on the duty to care for customers, underscoring the company's commitment to service and responsibility. The utility actively tracks the Momentary Average Interruption Frequency Index (MAIFI), which measures the frequency of short interruptions, as part of its performance metrics. This focus on reliability highlights the company's dedication to maintaining service quality despite growth-related pressures.

There are concerns about the capital module used for funding infrastructure projects. The need for low-cost financing is critical as large capital investments, necessary to keep pace with demand and technological advancements, could otherwise lead to higher rates for customers. The relationship with Infrastructure Ontario has been challenging, with issues such as unresponsiveness and potential major penalties for contract violations complicating efforts to secure financing to proceed with necessary infrastructure projects. These dynamics illustrate the complex environment in which the utility operates, balancing growth, financial health, and customer service

c. Rideau St. Lawrence Distribution (RSL)

The utility serves approximately 6,000 customers and has demonstrated improvement in its performance metrics, moving up from the third group to the second in the stretch factor rankings. The OEB's benchmarking has proven to be a useful tool for the utility. RSL actively looks to other utilities for innovative ideas and best practices. While these efforts have resulted in efficiency gains, such improvements are not seen by the utility to be fully captured in the current stretch factor assessment.

One challenge with the OEB's benchmarking approach is the lack of detail, particularly in accounting for the differences between urban and rural settings. RSL, which serves a mixed area, finds that the unique aspects of its service territory are not adequately reflected, indicating a need for more refined benchmarking criteria that take these variances into account.

Cost and reliability remain the primary concerns for RSL. To address these, RSL relies on organizations like the Electricity Distributors Association (EDA) and Cornerstone Hydro Electric Concepts (the CHEK group). These organizations have been instrumental in assisting RSL with the implementation of various initiatives, including Conservation and Demand Management (CDM) programs. Additionally, RSL has benefited from shared resources such as Geographic Information Systems (GIS) and a shared 'green button' solution, which have helped enhance service delivery and operational efficiency.

These collaborative efforts and strategic use of benchmarking tools underscore RSL's commitment to improving its service quality and operational effectiveness, despite the challenges posed by its diverse service area and the existing regulatory framework.

d. Burlington Hydro

Burlington Hydro serves approximately 70,000 customers, including residential (63,000), commercial (7,000), and large establishments such as major malls. The company primarily focuses on electricity distribution, but also offers billing services for water through affiliates. Cost of service applications have been filed in 2014 and 2021. Burlington Hydro has been assigned to the second group for the stretch factor, which has remained consistent over time.

With increased electrification, Burlington Hydro faces challenges as short-term benefits don't always reflect the costs incurred from distribution system investments such as charging station installations. Despite this, the company finds Incremental Capital Modules (ICM) and Advanced Capital Modules (ACM) attractive. Resources like the Electricity Distributors Association (EDA) and the Utilities Standards Forum (USF) have proven valuable for medium-sized utilities like Burlington Hydro.

The company has actively participated in discussions regarding inflation factors, particularly during an OEB (OEB) proceeding where they argued for adjustments to the calculation. Burlington Hydro continuously seeks efficiencies, but notes that the current model doesn't sufficiently incentivize cost reduction to reach the top tier.[130] Regulatory reviews, such as the Decision and Rate Order in 2021, have been constructive, leading to increased tracking of reliability and unit cost metrics, as well as asset replacement data. However, concerns remain about capital costs with longer payback periods, unlike the immediate revenue generation from past projects associated with new subdivisions.

Burlington Hydro has concerns about the accuracy of using GDP-IPI to track OM&A labour costs, citing examples like tree trimming and "locates services" where cost increases significantly exceed overall labour cost increases. While the 5-year regulatory cycle seems appropriate, challenges arise with Incremental Capital Module (ICM) for large, lumpy projects. The current TCB methodology is not seen to adequately accommodate such projects, like the upcoming smart meter replacements, which will significantly impact the company's annual capital expenditures.

Despite this, Burlington Hydro appreciates the transparency of the TCB, which provides detailed calculations annually. The company is also mindful of potential expansions in behind-the-meter DERs such as battery storage. It has not observed significant changes in its Load Duration Curve or 24-hour demand cycle. The balance between volumetric and fixed components of tariffs may become a future concern.

[130] Burlington Hydro costs are currently 12% below those predicted by the TCB model, placing it in the second tier. To reach the top tier, costs would need to be 25% below predicted levels, which would be very difficult to achieve while retaining high levels of customer service and reliability.

e. Grandbridge

GrandBridge Energy, formed by the merger of several utilities, delivers electricity to 113,000 customers across Brantford, Cambridge, North Dumfries, and Brant County. Mergers have streamlined cost applications, making them more realistic from a cost perspective. The company's strategic vision focuses on safety, culture, innovation, shareholder value, community ambitions, and growth.

In addition to electricity distribution, GrandBridge Energy provides water billing services for Brant County. The company has been assigned to Cohort 2 for the stretch factor, reflecting the diverse cohorts of its predecessor utilities.

GrandBridge Energy has experienced additional costs as a result of investments in grid automation and resiliency, EV adoption, new feeders and transformer stations, DERs, and the need for sophisticated real-time load forecasting.

The Incremental Capital Module (ICM) has been utilized for distribution investments and may be required for large data centers due to redundancy needs. The company relies on resources like the Electricity Distributors Association (EDA) for policy insights, the Utilities Standards Forum (USF), and the Gridsmart City Consortium for production, standardization, joint purchases and cybersecurity.

GrandBridge Energy acknowledges the concern of incurring capital costs earlier with longer payback periods. They have begun budgeting for smart meter replacements, opting to recertify and reseal existing meters rather than bulk replacement. Cable injection of underground ducts is also being explored to extend the life of underground capital.

While activity-based benchmarking is not a current focus, the company recognizes its potential for yardstick competition. Instead, GrandBridge Energy is prioritizing merger integration and acknowledges that utilities are at different stages in addressing resiliency and utilizing relevant software/IT.

f. Hydro One Networks Inc (HONI)

Hydro One Networks Inc. (HONI) distinguishes itself from other Ontario distributors due to its unique obligation to serve customers outside municipal service areas. It is the default distributor. Its responsibilities include remote communities. Additional unique features are its vast geographical coverage, and its large customer base of over 1.4 million. In addition to electricity distribution, HONI offers services like water billing and fiber optics through affiliates.

The company's stretch factor has improved over time, moving from the third cohort to the second group in 2017, with a decrease from 0.6 to 0.45.

In recent proceedings, HONI has relied upon reports prepared by Clearspring that incorporate data from approximately 80 U.S. utilities and HONI itself in the estimation of TCB models. Both the PEG and Clearspring emphasize the benefits of interjurisdictional data.

Opportunities for improving TCB modeling include better representation of business conditions in highly rural areas and incorporation of localized customer needs resulting from the energy transition. Investments in cybersecurity should also be considered.

The company notes that the OEB model has effectively not been updated in over a decade, relying on the coefficients estimated a decade ago, and therefore may not reflect the significant changes the industry has undergone. A carefully updated model could provide more contemporary benchmarking, including outputs that support the clean energy transition.

Nevertheless, total cost benchmarking (TCB) filed by distributors like HONI has improved due to a more applicable sample, including U.S. distributors, better adjustments for service territory conditions, and technical refinements in cost definitions and econometric procedures.

A renewed TCB needs to consider the new cost challenges of the ongoing energy transition, including the growing implicit outputs expected of utilities and the need to capture investments in energy transition infrastructure as outputs.

TCB is significantly more appropriate than activity and program-based benchmarking (APB) for stretch factor calibrations. This is due to APB's vulnerability to differing accounting practices and substitution issues, as well as its higher variance and error compared to TCB's tighter results range.

Appendix C Literature Review and Annotated Bibliography

C.1 Themes

This portion of the study conducts a literature review of scholarly, policy and trade sources that can inform our analysis of the approach taken to benchmarking and incentive regulation by the OEB. We organize the review around the following themes: A. Evolving Roles of Electricity Distributors, B. Incentive Regulation, C. Benchmarking Efficiency and Productivity and D. Additional Themes, which include quality of service, network security, alternate approaches to benchmarking, investment timing and studies from other industries (e.g., natural gas). Section 2, the Annotated Bibliography, contains brief summaries of papers roughly grouped according to these themes, though in some cases papers may align with more than one of the themes. Section 3, References, provides an extensive list of papers, studies and reports that relate to the subject matter of this study.

In developing this literature review we have conducted searches using keywords such as benchmarking, cost function estimation, total factor productivity, data envelopment analysis, stochastic frontier analysis, program-based benchmarking, price cap regulation, performance-based regulation, incentive regulation, and yardstick competition. We then conducted citation searches for relevant papers as well as searches of cited references within these papers. We also executed searches within specific publications including Utilities Policy, Energy Policy, Energy Economics, The Energy Journal, and Utility Dive, among others. Searches of energy research groups were conducted including the MIT Energy Initiative, MIT Center for Energy and Environmental Policy Research, Harvard Electricity Policy Group; Berkeley Energy Institute at Haas, Lawrence Livermore National Laboratory, Energy Policy Institute -- University of Chicago, Florence School of Regulation -- Electricity Group, and Energy Policy Research Group -- University of Cambridge.

Before proceeding, we highlight a few of the studies. Lowry (2023) conducts an empirical review of the efficacy of multiyear rate plans for Alberta distributors, finding that such plans have contributed to greater efficiency. Ajayi, Anaya and Pollitt (2022) use data envelopment analysis to analyze electricity networks in Great Britain and find that productivity growth has been approximately 1% per annum over the period 1990 to 2019. Crowley and Meitzen (2021) find that, under price-cap regulation, distributors in Ontario and Alberta have experienced lower escalation rates than utilities in the U.S. under traditional rate-of-return regulation. Senyonga and Bergland (2018) find that under yardstick competition, Norwegian distributors showed significant improvements in technical efficiency with productivity growth rates as high as 2% over the period 2007 to 2012. Kumbhakar and Lien (2017) also find that yardstick regulation of Norwegian utilities has contributed to significant productivity growth and efficiency improvements. On the other hand, Dimitropoulos and Yatchew (2017) find that over the period 2002-2012 Ontario distributors displayed negative observed productivity growth of about -1%. Coelli, Rao, O'Donnell and Battese (2005) provide a textbook treatment of approaches to efficiency and productivity measurement.

Clark and Samano (2022) analyze incentivized mergers in the Ontario electricity industry and conclude that these are unlikely to improve efficiency and lead to cost savings. Ghasemi, Dashti and Amiriou (2021) propose a mechanism for improving service quality. Gwerder, Figueiredo and Pereira da Silva (2019) discuss regulatory factors influencing smart grid investment. Agrell and Teusch (2015) make the case for yardstick competition in the Belgian electricity system. Nepal and Jamasb (2015) study incentive regulation in the context of network security. Evans and Guthrie (2012) study the timing of investment under price-cap regulation and find that firms tend to invest in increments that are too small to be socially optimal. Suzuki (2012) and Lowry and Getachew (2009) study incentive regulation in natural gas distribution.

C.2 Annotated Bibliography

a. Evolving Roles of Electricity Distributors

Anaya, K. L., Giulietti, M., & Pollitt, M. G. (2022). Where next for the Electricity Distribution System Operator? Evidence from a survey of European DSOS and National Regulatory Authorities. Competition and Regulation in Network Industries, 23(4), 245–269.

The paper examines optimal regulation of electricity distribution system operators (DSOs) post the EU Clean Energy Package, comprising Electricity Regulation (EU) 2019/943 and Electricity Directive (EU) 2019/944. Surveys of DSOs and national regulatory authorities (NRAs) in 39 European countries were conducted: 39 DSOs and 12 NRAs responded, representing 40% and 78% of customers respectively. The surveys addressed: (1) defining and regulating the DSO's future system operator role; (2) learning from transmission system operator (TSO) regulation for DSOs; and (3) how regulators enhance DSO capacity for system operation and coordination. The findings reveal ongoing evolution towards a more active DSO role, reflecting the recent adoption of the Clean Energy Package. Implementation of its provisions varies among Member States, impacting regulatory dynamics. The study underscores the complexity of transitioning DSOs to more active roles and highlights the learning process from TSO regulation. It suggests a need for regulatory support to bolster DSO capacity for effective system operation and coordination. Overall, the findings emphasize the ongoing nature of regulatory adaptation in response to evolving energy frameworks.

Marques, V., Costa, P. M., & Bento, N. (2022). Greater than the sum: On regulating innovation in Electricity Distribution Networks with externalities. Utilities Policy, 79, 101418.

The paper discusses the necessity of developing suitable regulatory models to drive investment in new technologies for modernizing electricity distribution networks amidst the energy transition. It highlights the need for understanding the externalities associated with grid modernization and emphasizes the importance of incentivizing investments in new technologies for decarbonization. The study aims to determine the most appropriate regulatory approach by considering the diverse effects of innovation and their implications for grid modernization. The authors develop a decision model that explicitly incorporates the benefits, costs, and spillover effects of technology innovations, focusing on Advanced Metering Infrastructure (AMI), Advanced Substation Feeder Automation (ASFA), and microgrids (µG). These technologies are seen as crucial for the short-term digitalization and modernization of distribution networks. The paper proceeds to explore the benefits of the three representative innovations in distribution networks and reviews relevant literature. It then presents the decision model and applies it to the technology innovations under analysis. A general regulatory framework is proposed, considering externalities and technological risks, and their impact on the regulator's actions regarding incentive regulatory schemes. The main results, theoretical implications, limitations, and suggestions for future research are discussed, providing insights into fostering innovation in electricity distribution networks through effective regulatory mechanisms.

Bovera, F., Delfanti, M., Fumagalli, E., Lo Schiavo, L., & Vailati, R. (2021). Regulating electricity distribution networks under technological and demand uncertainty. Energy Policy, 149, 111989.

The paper explores the evolving landscape of regulating electricity distribution networks in light of changing consumer preferences, increasing distributed energy resources, and advanced information technologies. It focuses on the regulatory practices in Great Britain and Italy, where advanced instruments are used to determine allowed revenues amid technological and demand uncertainties. The authors propose a novel regulatory approach that enhances existing mechanisms by providing a modular ex-post estimate of efficient total expenditures. This approach aims to address benchmark errors that occur when regulators fail to anticipate emerging cost-saving technologies or network management practices. By allowing firms to retain gains from efficiency improvements while fostering innovation, the proposed approach aligns with the complexities outlined in EU Directive 2019/944 regarding the expanding role of distribution operators. The paper discusses the transformative effects of technological innovations on distribution networks, driven by decarbonization policies. It emphasizes the need for regulatory adaptation to accommodate bidirectional power flows, advanced metering, and changes in market design. The proposed approach offers a structured method for regulators to estimate efficient expenditure while incentivizing firms to innovate within defined boundaries, thus managing benchmark errors effectively. The paper concludes by discussing the incentive properties of the proposed approach and deriving policy implications, highlighting its potential to encourage efficiency gains and innovation in network planning and operation.

Burger, S. P., Jenkins, J. D., Batlle, C., & Pérez-Arriaga, I. J. (2019). Restructuring revisited part 1: Competition in electricity distribution systems. *The Energy Journal*, *40*(3), 31-54.

Burger, Scott, Jesse D. Jenkins, Carlos Batlle, Ignacio J. Pérez-Arriaga (2019) Restructuring Revisited Part 2: Coordination in Electricity Distribution Systems The Energy Journal, 40: 3, 55-76.

These two papers address the complexities of evolving electricity distribution systems. The first paper explores the impact of distributed energy resources (DERs) on competition within electricity distribution systems, highlighting the need for regulatory and policy adjustments in response to the sector's decentralization. Originally designed for a centralized energy system with relatively inelastic demand, current regulations may no longer be suitable.

The study examines the economic roles of distribution network owners and operators, DER owners, and aggregators and retailers. It applies foundational industrial organization theories and lessons from past power system restructuring to the contemporary landscape, aiming to answer three critical issues:

- whether the operations of distribution system operators (DSOs) should be separated from distribution network ownership to maintain neutrality;
- whether distribution network operators (DNOs) should have the ability to own and operate DERs, or if DER ownership should remain with competitive entities exclusively;
- whether the rise of DERs calls for a re-evaluation of competition's role in aggregation services, such as retailing.

The second paper addresses the mechanisms needed to coordinate vertically and horizontally disaggregated actors in electricity distribution systems. The mechanisms designed to coordinate planning, investments, and operations in the electric power sector were developed with minimal participation from either the demand side of the market or distributed energy resources (DERs) connected at distribution voltages. The emergence of DERs is now animating consumers and massively expanding the number of potential investors and participants in the provision of electricity services. We highlight how price signals—the primary mechanism for coordinating investments and operations at the transmission level—do not adequately coordinate investments in and operations of DERs with network infrastructure. The paper discusses the role of the distribution system operator in creating cost-reflective prices, and argues that the price signals governing transactions at the distribution level must increasingly internalize the cost of network externalities, revealing the marginal cost or benefit of an actor's decisions. Price signals considered include contractual relationships, organized procurement processes, market signals, and regulated retail tariffs.

Makholm, J. D. (2018). The rise and decline of the X factor in performance-based electricity regulation. The Electricity Journal, 31(9), 38-43.

The authors outline the experiences of implementing 'RPI minus X' form of Performance-Based Regulation (PBR) within the North American utility industry. Although this form of PBR was lauded for its potential to bypass cost-plus efficiencies, its application in North America has been complicated by differences in regulatory environments. The authors argue that rapid transformation in electricity distribution and grid modernization poses a practical challenge in measuring factor productivity and setting an appropriate X factor. They conclude that these drastic changes in the utilities sector require a more nuanced regulatory approach, such as using direct performance measures and targeted incentives.

Jenkins, J. D., & Pérez-Arriaga, I. J. (2017). Improved regulatory approaches for the remuneration of electricity distribution utilities with high penetrations of distributed energy resources. The Energy Journal, 38(3), 63-92.

The study by Jenkins and Pérez-Arriaga (2017) titled Improved Regulatory Approaches for the Remuneration of Electricity Distribution Utilities with High Penetrations of Distributed Energy Resources", addresses the challenges that electricity distribution utilities face with the increasing penetration of distributed energy resources (DERs). The authors suggest that due to increasing uncertainty in network use and the evolution of system costs, traditional regulatory models, like cost of service and incentive-based frameworks, are no longer sufficient. To counter these challenges, Jenkins and Pérez-Arriaga propose a novel methodology for establishing allowed utility revenues over a multi-year regulatory period, designed to adapt to the dynamic nature of DER integration and ensure fair remuneration for distribution utilities. The authors use a reference network model to simulate a large-scale urban distribution network, demonstrate practical uses for this methodology, and illustrate performance given benchmarks and forecast errors. Their methodology aims to balance the need for investment in the distribution network with the goal of promoting efficiency and innovation in the sector. By incorporating mechanisms that adjust allowed revenues based on actual investment and operational efficiencies, the proposed approach seeks to provide a more predictable and stable regulatory environment.

Pérez-Arriaga, I. J., Jenkins, J. D., & Batlle, C. (2017). A regulatory framework for an evolving electricity sector: Highlights of the MIT 'Utility of the Future' study. Economics of Energy & Environmental Policy, 6(1), 71–92.[131]

The electric power sector is undergoing significant evolution due to the emergence of distributed energy resources and advancements in computing, communication, and control technologies. These developments are offering electricity consumers an unprecedented level of choice, though current electricity rates and incentives, designed for a simpler era, may not adequately guide these choices. Additionally, these technologies provide new opportunities for regulated utilities, competitive suppliers, and other businesses to offer electricity services. The paper summarizes findings from a two-year multidisciplinary research effort by the MIT Energy Initiative, titled the Utility of the Future. It proposes a framework for proactive reforms in electricity regulation, market, and policy aimed at facilitating the efficient evolution of the power sector. Key recommendations include establishing a comprehensive system of efficient prices and charges for all electricity users, enhancing the regulation of distribution utilities, reconsidering industry structure to prevent conflicts of interest, and making improvements to electricity markets. The framework aims to create a level playing field for the provision and consumption of electricity services and to support the integration of a cost-effective mix of centralized generation, conventional network assets, and emerging distributed resources.

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[131] MIT Energy Initiative, *Utility of the future*. (2016). https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf. See also the earlier study MIT Energy Initiative report *The Future of the Electricity Grid* (2011), https://energy.mit.edu/research/future-electric-grid/.

This summary paper and the underlying extensive report contains five recommendations specifically directed toward the distribution segment of the industry (pp. 80-82):

- "Reward utilities for cost-savings."
- "Equalize incentives for efficiency in capital and operational expenditures."
- "Implement measures to manage inherent uncertainty in utility remuneration and to reduce information asymmetry."
- "Create output-based incentives for performance and quality of service improvements."
- "Establish explicit incentives for long-term innovation."

Costello, K. (2012). The challenges of new technologies for state utility regulators. The Electricity Journal, 25(2), 32-43.

This study examines the significant challenges that new technologies pose for state utility regulators. Costello explores eight challenges faced by regulators: (1) Becoming informed about technological innovation and information asymmetry, (2) Technology evaluation, (3) Alignment of utility rewards with utility risks, (4) Allocation of risk between utilities and taxpayers, (5) Maintaining utility accountability, (6) Inevitable trade-offs, (7) Distinguishing between due and undue regulatory barriers to innovation, (8) The proper role of utilities. Costello highlights the most obvious challenge: the existing traditional regulation may not offer utilities the environment required for investing in new technologies and promote public interest. This dilemma centers around finding a balance between protecting customers from excessive risks associated with new technological investments and providing utilities with sufficient incentives to pursue potentially beneficial investments. Costello's analysis suggests that the rapid pace of technological advancement in the energy sector necessitates a re-evaluation of regulatory practices. Re-evaluation allows for better innovation and ensures that utilities can effectively respond to the evolving demands of society.

b. Incentive Regulation

Joskow, P. (2024, February 6). The expansion of incentive (performance based) regulation of electricity distribution and transmission in the United States. CEEPR. https://ceepr.mit.edu/workingpaper/the-expansion-of-incentive-performance-based-regulation-of-electricity-distribution-and-transmission-in-the-united-states/

The paper argues that the adoption of incentive regulation or Performance-Based Regulation (PBR) for electric distribution companies in the U.S. has been initially slow but is now gaining momentum among state regulators. PBR should be viewed as comprising various 'building blocks' that can be individually applied or combined into a comprehensive strategy, often adopted sequentially to ease regulators into the system. It clarifies that PBR is more complex than a mere dynamic price cap mechanism, encompassing elements like ratchets, performance benchmarking, profit sharing, quality incentives, and targeted incentives to meet broader policy goals beyond just controlling prices and costs.

The gradual expansion of PBR is attributed to factors such as limited resources available to state regulators and misunderstandings of the 'RPI-X' mechanisms in Great Britain, which have developed beyond simple price caps. Changes in the responsibilities of distribution companies over the last two decades have underscored the importance and appeal of PBR mechanisms, despite making their design and application more challenging due to resource constraints. These limitations have encouraged learning from other states and countries, particularly Great Britain, and reliance on external advisors and consultants. State regulatory bodies are becoming more receptive to PBR as it aligns more closely with the regulatory challenges they encounter, suggesting a positive trend towards its wider adoption.

> "… a dynamic price cap mechanism is one component of a comprehensive PBR mechanism. With uncertainty, asymmetric information, moral hazard, rent extraction goals, budget balance constraints, etc., a simple forever price cap mechanism for electric distribution and transmission companies is optimal only under a very stringent and implausible set of assumptions. These considerations naturally lead to ratchets, performance benchmarking, profit sharing mechanisms, menus of contracts, quality incentives, and targeted incentives consistent with the broader set of policy goals beyond prices and costs." (p.53)

von Bebenburg, C., Brunekreeft, G., & Burger, A. (2023). How to deal with a CAPEX-bias: fixed-OPEX-CAPEX-share (FOCS). Zeitschrift für Energiewirtschaft, 47(1), 54-63.

In recent years, the CAPEX-bias in regulation, which occurs when regulations incentivize choosing capital expenditure (CAPEX) over operational expenses (OPEX) or vice versa, has gained renewed attention due to decarbonization and digitalization efforts. The issue was first highlighted by Averch and Johnson in 1962. This paper proposes a solution to address the CAPEX-bias called the fixed-OPEX-CAPEX-share (FOCS) approach. FOCS treats all expenses as TOTEX, with a fixed portion capitalized as quasi-CAPEX and the remainder treated as quasi-OPEX. These are then regulated in the same way as traditional CAPEX and OPEX. By fixing the capitalization rate, firms become indifferent between CAPEX and OPEX, eliminating the bias. The paper discusses three implementation issues: scope of application, depreciation, and the capitalization rate. Practical experience in the UK suggests that a TOTEX or FOCS approach helps reduce the CAPEX-bias and improves value for consumers. Regulatory methodologies used by Ofgem and Ofwat provide useful precedents for future implementations in other jurisdictions.

Costello, K., (2023). Multi-year rate plans are better than traditional ratemaking: not so fast. Electr. J. 36.

The goal of ratemaking in the utilities sector is to achieve economic efficiency with fairness and reasonable regulatory costs. Economic efficiency requires utilities to create or adopt new technologies, achieve excellent operating performance, and set rates equal to marginal cost. The traditional method has been to apply rate plans on an annualized basis (12 months). These methods have been critiqued since the early 1960s. A different method is to use multi-year rate plans, which set base rates and revenue requirements at a longer timeframe. In the United States, Georgia, Minnesota, and Washington have either approved multi-year rate plans (MRP's) or expressed interest in these methods. They have enjoyed considerable support from U.S. electric utilities, with the argument it would reduce regulatory lag, though falling short of explaining how this would make a compelling case for customers. MRP's would facilitate the recovery of capital costs between general rate cases.

The purpose of this study is to evaluate MRP's from the regulator's point of view. Utility customers in theory could benefit from lower prices, more moderate price changes over time, higher utility supply of services, higher reliability and customer service, and more immediate price benefits from utility improvements. While MRP's have attractive features warranting serious attention from regulators, a caveat is that "benefits to utility customers come down to how MRPs are structured and executed".

Brunekreeft, G. (2023). Improving regulatory incentives for electricity grid reinforcement. Constructor University, Bremen.

Recent shifts in electricity regulation reflect a transition from efficiency-oriented to investment-oriented approaches, accommodating the need for network adjustments and expansions driven by new energy transitions. An emerging trend is output-oriented regulation (OOR), which adds revenue elements based on achieving specific regulatory output targets, incentivizing investments and activities that may require increased costs or upfront expenditures. This study, conducted for the Netherlands' Authority for Consumers and Markets (ACM), focuses on incentivizing grid operators for grid reinforcement, including expansion and capacity improvement, with applicability to a general regulatory context but drawing on Dutch examples.

Four base regulatory models are evaluated—investment budgets, CAPEX true-up for Transmission System Operators (TSO) and Distribution System Operators (DSO), and price/revenue-cap—each assessed for effectiveness, efficiency, affordability, implementation, and sustainability. The study introduces eight OOR elements to complement these models, including Fixed OPEX CAPEX shares (FOCS), Flexshare combined with FOCS, bonus/malus systems for connection and construction times, outage cost incentives, KPI-based smart grid development, System Development Plans (SDP), cost-benefit sharing, and rate of return adders for significant investments.

The analysis concludes that certain OOR elements like FOCS, SDP, and rate of return adders moderately reinforce the grid without major trade-offs, while others, such as cost-benefit sharing, show promise for system optimization but face challenges in implementation due to complexity. Smart-grid index development and strategies to manage outage costs and incentivize connection times are highlighted as effective but potentially costly or broad in scope.

The study suggests a gradual approach, starting with CAPEX true-up and benchmarking, while noting the necessity to address CAPEX-bias and the potential for integrating OOR elements into the base model to counter strategic underspending. The current price/revenue-cap model, emphasizing efficiency over investment, could be enhanced by additional OOR elements, albeit at the risk of increased regulatory complexity and conflicting incentives.

Poudineh, R., Brandstätt, C., & Billimoria, F. (2022). Economic Regulation of Electricity Distribution Networks. In Electricity Distribution Networks in the Decentralization Era: Rethinking Economics and Regulation (pp. 117-131). Cham: Springer International Publishing.

Traditional regulatory models for electricity network companies have historically prioritized cost efficiency and reliability, but with the increasing emphasis on energy transition and decarbonization objectives, the need for innovation and activities promoting these goals has become paramount. This necessitates a regulatory shift towards frameworks that incentivize innovation and the deployment of low-carbon technologies. However, designing effective incentive schemes for innovation is challenging due to information asymmetry between network firms and regulators, as regulators are unable to observe the effort or opportunities for innovation within these firms. To address this challenge, regulators may condition allowed revenue on firm performance, but the uncertain outcomes of innovation efforts pose a risk of penalizing genuine efforts that yield unsuccessful outcomes. Therefore, regulatory frameworks must strike a balance between incentivizing innovation and managing risk. This balance can be achieved through input-oriented models focusing on the cost of innovation activities or output-oriented models focusing on innovation outcomes. Each approach has its limitations, and the choice between them depends on factors such as policy objectives, uncertainty levels, and the risk attitude of network utilities. Innovative regulatory mechanisms, such as competitive mechanisms for allocating innovation funds, can also provide incentives for innovation, but regulators must address issues of risk attitude heterogeneity among bidders and ensure that smaller companies have opportunities to participate without facing excessive risk. Examples like the UK's RIIO model, which combines price control mechanisms.

Sappington, D. E., & Weisman, D. L. (2021). Designing performance-based regulation to enhance industry performance and consumer welfare.

The authors provide two observations on the design and implementation of performance-based regulation (PBR) in the utilities sector. The first observation is how mitigating the ‘ratchet effect’ by utilizing external performance benchmarks over internal ones can increase incentives and achieve superior firm performance. Secondly, the authors discuss the challenge of information asymmetry for regulators. To address this, they propose offering firms a choice among carefully designed regulatory options to leverage their insider knowledge for consumer benefit. Lastly, the authors argue for the emulation of competitive market dynamics through PBR, suggesting gains in productivity performance and consumer welfare.

Kuosmanen, T., & Johnson, A. L. (2021). Conditional yardstick competition in energy regulation. The Energy Journal, 42(1 suppl), 1-26.

This paper explores the application of conditional yardstick competition in the domain of energy regulation. Conditional yardstick competition, as outlined in the study, is a regulatory approach designed to improve efficiency in the energy sector by comparing the performance of firms against a set of peers or benchmarks. This method adjusts for differences in operating conditions among firms, making the comparisons fairer and more accurate. The authors argue that this approach can result in significant improvements in both efficiency and service quality. They provide a comprehensive framework for implementing conditional yardstick competition, emphasizing its potential to incentivize firms to innovate and reduce costs without compromising service quality.

The study further delves into the empirical application of this regulatory method in various energy markets, using the real-world application of the proposed regime to Finnish electricity distribution firms in 2016-2023. Kuosmanen and Johnson meticulously analyze the outcomes of conditional yardstick competition on different facets of energy provision, including pricing, consumer satisfaction, and environmental impact. Their findings suggest that this approach not only fosters competitive behavior among energy providers but also aligns with broader policy objectives such as sustainability and energy security.

Lowry, M. N., & Hovde, D. A. (2021). Escalating power distributor O&M revenue. The Electricity Journal, 34(6), 106975.

This paper examines the evolving landscape of operation and maintenance (O&M) revenue models for power distributors. The authors address the critical need for power distribution companies to adapt their revenue structures in response to the increasing complexity and demands of the modern energy grid. They argue that traditional O&M revenue models, which largely depend on fixed rates and volume-based billing, are becoming insufficient due to the rapid advancement of renewable energy sources, the decentralization of power generation, and the integration of smart grid technologies. Lowry and Hovde propose that escalating the O&M revenue is vital for sustaining the financial health of power distributors, ensuring they can maintain and improve the grid's reliability and efficiency.

In their analysis, Lowry and Hovde detail a range of strategies and mechanisms that could be implemented to enhance O&M revenue streams. These include the adoption of performance-based ratemaking, which ties revenue to specific performance metrics, and the introduction of dynamic pricing models that reflect the real-time costs of power distribution and the value of reliability to consumers. The authors also highlight the importance of regulatory support in facilitating these changes, underscoring the role of policy in enabling a more flexible and responsive O&M revenue framework.

Poudineh, R., Peng, D., & Mirnezami, S. R. (2020). Innovation in regulated electricity networks: Incentivizing tasks with highly uncertain outcomes. Competition and Regulation in Network Industries ,21(2), 166-192.

This article discusses the challenge of incentivizing innovation in electricity networks, which is crucial for the energy transition. Traditional regulatory models focus on cost-efficiency, but innovation requires a different approach due to its inherent risk. The regulator faces the task of balancing risk-sharing with incentivizing innovation. Mechanisms that overlook innovation's risk can hinder progress by diverting attention from innovation to efficiency gains. Differentiating between cost-efficiency and innovation in regulation is essential for facilitating the transition. An effective regulatory scheme should differentiate between types of innovation activities and adapt its approach accordingly. Input-based regulation works well for riskier activities like R&D, while output-based regulation is suitable for less risky endeavors. The risk attitude of network companies is also critical, and regulatory schemes should consider it to ensure fair competition for innovation funds. A two-stage competition process and offering smaller funds for preliminary projects are proposed as approaches to address this issue and promote innovation in electricity networks.

Kaufmann, L. (2019). The past and future of the X factor in performance-based regulation. The Electricity Journal, 32(3), 44–48.

This article challenges the notion that 'Inflation minus X' regulation, prevalent in the UK, is unlikely to expand in the US. It contests three key perspectives: 1) its origin as a UK import, 2) the difficulty in objectively reflecting current utility costs, and 3) the movement towards targeted incentives. Contrary to these views, the article argues that 'Inflation minus X' plans originated in the US and can accurately reflect current utility conditions. It highlights ongoing regulatory changes prompted by structural shifts in energy utilities, as indicated by Utility Dive's survey predicting a move towards performance-based regulation (PBR). The trend towards incentive-based mechanisms is evident in Canada's provinces, with Ontario and Alberta implementing PBR for utilities. Despite skepticism from some regulatory economists, the article contends that 'Inflation minus X' MRPs offer a viable regulatory mechanism in North America. It argues that they are not solely a UK import and can complement targeted incentives effectively. In conclusion, while the expansion of 'Inflation minus X' MRPs in North America remains uncertain, they are seen as a potentially valuable regulatory tool alongside evolving incentive-based approaches in the energy sector.

Lowry, M.N., Deason, J., Makos, M., (2017). State Performance-Based Regulation Using Multiyear Rate Plans for US Electric Utilities [White paper]. Lawrence Berkeley National Laboratory.

This paper discusses the adoption of state performance-based regulation (PBR) using multiyear rate plans (MRPs) for U.S. utilities. This study provides a comprehensive analysis of how electric utilities, which are predominantly investor-owned and regulated by state utility commissions, can contain costs while addressing the need for system modernization amidst significant changes in technology, customer preferences, and competitive pressures. The authors argue that MRPs offer several advantages over traditional cost-of-service regulation by incentivizing utilities to improve efficiency and service quality over longer periods, thereby aligning their financial interests with broader policy goals such as reliability, affordability, and environmental sustainability.

The report delves into the mechanics of PBR and its implications for utility performance and system modernization efforts. It examines how multiyear rate plans, coupled with performance incentive mechanisms, can drive utilities to optimize operations and invest in necessary infrastructure upgrades without frequent rate case proceedings. By providing utilities with a more stable regulatory environment and clearer performance expectations, these plans can facilitate the transition to a more dynamic and resilient electricity sector.

Joskow, P. L. (2014). Incentive regulation in theory and practice: electricity distribution and transmission networks. Economic regulation and its reform: What have we learned? 291-344.

In this paper, Joskow delves into the intricacies of incentive regulation and its application to electricity distribution and transmission networks. The text outlines the evolution of regulatory approaches over the past three decades, particularly focusing on the shift from state-owned or private regulated monopolies towards more privatized, restructured, and in some segments, deregulated frameworks. This transition is critically examined across various network industries, including electricity, to understand the impact of regulatory reform programs that involve the vertical separation of competitive segments from network segments that continue to be regulated. Joskow's analysis highlights the necessity for incentive regulation in ensuring efficient operation and investment in the electricity sector, amidst the complexities introduced by these structural changes.

Joskow further explores the theoretical underpinnings and practical applications of incentive regulation mechanisms, specifically within the context of electricity networks. He discusses the challenges posed by information asymmetry between regulators and utilities, the objectives of promoting efficiency, and the importance of aligning incentives with these objectives. The text provides a comprehensive review of incentive regulation's effectiveness in addressing issues related to investment, cost control, and service quality in electricity distribution and transmission.

Joskow, P. L. (2012). Creating a smarter U.S. Electricity Grid. Journal of Economic Perspectives, 26(1), 29–48.

This paper focuses on the transformation and enhancement of the United States' electricity grid. The author delves into the challenges and opportunities associated with developing a more intelligent and efficient grid system. Joskow emphasizes the importance of integrating advanced technologies, such as smart meters and digital communication, to enable real-time monitoring and control of electricity consumption. The article explores the potential benefits of a smarter grid, including improved reliability, increased energy efficiency, and better integration of renewable energy sources. Additionally, Joskow discusses the regulatory and institutional changes necessary to facilitate the transition to a smarter grid. The article concludes by highlighting the need for continued investment, research, and collaboration among stakeholders to address the complex issues involved in modernizing the U.S. electricity grid. Overall, Joskow provides valuable insights into the challenges and opportunities associated with creating a more intelligent and responsive electricity infrastructure in the United States.

Jamasb, T., Orea, L., & Pollitt, M. (2012). Estimating the marginal cost of quality improvements: The case of the UK electricity distribution companies. Energy Economics, 34(5), 1498–1506.

This paper develops an econometric model to estimate the marginal costs associated with quality improvements in the UK electricity distribution sector. Their research aims to provide energy regulators with a tool to design better incentive mechanisms for utilities, encouraging them to enhance service quality and thus reduce welfare losses from suboptimal performance. By applying their methodology to UK electricity distribution networks, the authors assess the welfare impacts of quality improvements observed between 1995 and 2003. Their findings indicate that regulatory incentives for reducing service interruptions were insufficient for achieving economically efficient levels of service quality. However, incentives aimed at decreasing network energy losses showed some effectiveness in improving performance. The study concludes that the quality improvements during the analyzed period represented only about 20% of the potential customer welfare gains, highlighting a substantial opportunity for further enhancements in service quality to achieve economically efficient outcomes. This work underscores the importance of accurately estimating the costs of quality improvements to inform regulatory policies and incentive mechanisms in the energy sector.

Sappington, D. E., & Weisman, D. L. (2010). Price cap regulation: What have we learned from 25 years of experience in the telecommunications industry? Journal of Regulatory Economics, 38(3), 227–257.

Price cap regulation (PCR) in the telecommunications industry, adopted in the UK in 1984, has been widely used globally over the last 25 years as an alternative to rate of return regulation (ROR). This regulation grants firms some pricing discretion while constraining average price increases. Regulators adjust the maximum rate of inflation-adjusted price increases annually to align with the economy-wide inflation rate. Unlike ROR, PCR provides incentives for innovation and cost reduction by allowing firms to deviate from anticipated returns. Earnings sharing regulation (ESR) offers moderate incentives for innovation and cost reduction. It allows firms to keep earnings within a specified range, sharing incremental earnings with customers outside that range. ESR resembles PCR within the no-sharing range but shares incremental earnings with customers above or below that range. PCR and ESR offer different approaches to regulation, influencing firms' incentives for investment, innovation, and cost reduction. While ROR ensures a reasonable return on investment, it may discourage cost reduction and innovation. In contrast, PCR and ESR promote innovation and cost reduction by temporarily severing the link between realized costs and allowed prices. The experience with incentive regulation in the telecommunications industry provides insights for regulatory policies in other industries, although definitive conclusions may be challenging due to institutional and technological differences.

Joskow, P. L. (2008). Incentive regulation and its application to electricity networks. Review of Network Economics, 7(4).

This paper explores the evolution of incentive regulation and its application on regulating unbundled electricity transmission and distribution networks. Joskow focuses on the challenges and opportunities presented by unbundled electricity networks. Furthermore, the author explores the complex interplay between regulatory mechanisms and the asymmetric information problems inherent in utility regulation, where regulators often possess less information about operational costs, managerial effort, and service quality than the utility companies themselves. Through this analysis, Joskow underscores the importance of designing regulatory frameworks that can effectively align the interests of utilities with those of consumers and regulators, particularly in promoting efficiency and service quality.

The paper also provides an insightful review of the implementation of price cap mechanisms and quality of service incentives, with a specific focus on the UK's experience. Joskow's discussion highlights how these regulatory tools have been employed to incentivize utilities to reduce costs while maintaining or improving service quality. By critically assessing both the theoretical underpinnings and practical applications of incentive regulation, Joskow contributes to a deeper understanding of its effectiveness and limitations.

Shuttleworth, G. (2005). Benchmarking of electricity networks: Practical problems with its use for regulation. Utilities Policy, 13(4), 310–317.

This article critically examines the use of benchmarking in the regulation of electricity networks. The author highlights the practical problems and limitations associated with the application of benchmarking techniques in this specific context. Shuttleworth argues that while benchmarking has been widely used in the electricity industry to measure the performance and efficiency of network operators, there are several challenges that need to be addressed. One of the major issues is the lack of accurate and reliable data required for benchmarking analysis. The author points out that the data provided by network operators may not be consistent or may not cover all relevant aspects, hindering the accuracy and comparability of benchmarking results. Another challenge highlighted by Shuttleworth is the complexity and uniqueness of electricity networks. The author argues that it is difficult to develop a standardized benchmarking framework that adequately captures the specific characteristics of different networks. Factors such as geography, population density, and regulatory environments can significantly impact the performance and costs of electricity networks, making direct comparisons challenging. Moreover, the author stresses the importance of considering external factors and market conditions that may influence network performance. Benchmarking analysis often fails to account for external factors such as weather events, changes in demand patterns, or technological advancements that impact the performance and cost efficiency of electricity networks. Shuttleworth suggests that while benchmarking can provide some valuable insights for regulatory purposes, it should be used cautiously and complemented with other regulatory tools. The author emphasizes the importance of considering context-specific factors, providing appropriate incentives for network operators, and focusing on the long-term outcomes of regulation rather than relying solely on benchmarking. Overall, the article calls for a more nuanced and comprehensive approach to regulation that takes into account the limitations and practical challenges of benchmarking in the electricity network sector.

Yatchew, A. (2001). Incentive regulation of distributing utilities using yardstick competition. The Electricity Journal, 14(1), 56-60.

Performance-based regulation (PBR) aims to minimize costs, promote efficient investments, ensure fair returns for firms, and improve information sharing between regulators and companies. Yardstick competition, comparing firms' performance, helps achieve these goals. However, setting meaningful benchmarks is challenging, especially with diverse utilities. The article discusses using econometric approaches in Ontario, Canada, where over 150 utilities serve 12 million people. It suggests comparing firms' costs through averages, medians, or percentiles to incentivize efficiency while ensuring fairness and transparency. The analysis examines 81 municipal distributing utilities in Ontario, focusing on factors influencing the cost of electricity distribution per customer. The model includes variables like customer count, wage rates, capital costs, and utility type. Results show that higher wage rates and longer wire lengths per customer tend to increase costs, while Public Utility Commissions (PUCs) benefit from economies of scope, resulting in lower costs. In conclusion, explaining cost differences among utilities and determining allowable costs leads to fairer regulatory rules. Jurisdictions with too few firms for robust analysis, empirical data from other regions becomes more important. Additionally, linking regulatory rules to utility differences incentivizes firms to disclose information, improving transparency. Incentive regulation not only encourages cost-effective behavior but also fosters better information disclosure.

Bernstein, J.I, and D. M. Sappington (1999),Setting the X-factor in Price Cap Regulation Plans, Journal of Regulatory Economics, 16: 5-25

Despite widespread use of price-cap regulation, the literature as of 1999 has provided little guidance on X-factor determination (the rate at which inflation-adjusted output prices must fall under price-cap plans). The technique has been very popular in telecom industries. This provides stronger incentives for cost reduction and technological innovation than ROR (rate of return) regulation. When distanced from realized production costs and earnings, the firm benefits from reducing its operating costs. This is absent in cost-based or ROR regulation where authorized prices are linked to realized costs.

This study reviews standard industry practices regarding the determination of the X-factor and discusses the extant economic literature. The X-factor should 'reflect the extent to which the TFP growth rate in the regulated industry exceeds the corresponding growth rate in the rest of the economy; and the prices of inputs employed by firms in the regulated industry are rising less rapidly than the prices of inputs employed by the other firms in the economy'. In the event of a subset of the firm's products being regulated, X-factors should be reduced when the prices of the firm's other products are rising relatively slowly. The paper provides useful analysis but not a clear method for determining the appropriate X-factor in all instances.

Schleifer, Andrei (1985), A Theory of Yardstick Competition, Rand Journal of Economics, 16:3 319-327.

Cost-of-service regulation is commonly applied to franchised monopolies in the United States, aiming to align prices with incurred costs while ensuring firms supply necessary services. However, this scheme fails to incentivize cost reduction by the regulated firm, as prices track costs, leading to inefficiencies. To address this, lagged price adjustment is suggested, but it has limitations. An alternative approach proposed is yardstick competition, where regulators compare similar regulated firms to set benchmarks for cost evaluation. This method draws parallels with existing practices in other sectors, such as Medicare's reimbursement system for hospitals and the Defense Department's dual-sourcing strategy. Yardstick competitions aim to incentivize firms to reduce costs by comparing their performance to that of similar firms. This regulatory scheme is particularly effective when applied to identical firms, where regulators can expect similar cost reduction capabilities. Even in cases of heterogeneous firms, yardstick competition can outperform cost-of-service regulation, especially when accounting for differences in firms' characteristics. The study outlines a model to illustrate how yardstick competition works and compares it with the social optimum and cost-of-service regulation. It concludes that yardstick competition can be a robust and effective regulatory mechanism, promoting cost control and efficiency.

c. Benchmarking Efficiency and Productivity

Lowry, M.N. (2023) Impact of multiyear rate plans on power distributor productivity: Evidence from Alberta

This paper investigates the effectiveness of multiyear rate plans (MRPs) in enhancing the productivity of power distributors in Alberta. The study analyzes the implementation of MRPs as a regulatory mechanism designed to incentivize efficiency and productivity improvements in the power distribution sector. The authors argue that MRPs, by providing predictable revenue streams and allowing for cost recovery over extended periods, encourage power distributors to invest in infrastructure and technological advancements, ultimately leading to improved operational efficiency and service quality. The research leverages data from Alberta's power distribution industry to empirically assess the impact of MRPs on distributor performance, focusing on metrics such as cost efficiency, reliability, and customer service.

The findings of the study reveal that MRPs have a significant positive effect on the productivity of power distributors in Alberta, highlighting the benefits of regulatory stability and the encouragement of long-term planning and investment. Lowry demonstrates that under MRPs, distributors are more likely to undertake efficiency-enhancing measures and adopt innovative technologies that contribute to operational improvements. The study concludes by emphasizing the importance of careful design and implementation of MYRPs, including the establishment of appropriate performance benchmarks and incentives, to maximize their potential benefits for all stakeholders.

Ajayi, V., Anaya, K., & Pollitt, M. (2022). Incentive regulation, productivity growth and environmental effects: The case of electricity networks in Great Britain. Energy Economics, 115, 106354.

The paper examines the productivity growth of electricity transmission and distribution networks in Great Britain, focusing on how changes in incentive mechanisms and regulatory pressure affect measured total factor productivity (TFP). It underscores the importance of adjusting productivity measures to account for regulatory efforts aimed at reducing societal impacts and enhancing service quality in the electricity sector. Using Data Envelopment Analysis (DEA), the study finds consistently low productivity growth rates of around 1% annually from 1990/1991 to 2018/2019. The analysis attempts to monetize a broader range of quality and emissions variables to demonstrate their impact on measured productivity growth, highlighting both positive and negative effects, albeit often small. The paper discusses the evolution of incentive mechanisms in the regulatory framework, emphasizing the interplay between efficiency incentives, specific incentive mechanisms, and quality of service targets. It explores how changes in incentives influence productivity growth and addresses the challenge of balancing cost reduction with environmental sustainability and service quality improvement. By employing the Malmquist index and DEA method, the study disentangles the sources of productivity growth and compares productivity among firms and over time. DEA's ability to capture changes in underlying data and reflect changes in productivity makes it a relevant tool for assessing productivity in regulated industries. The paper concludes by presenting the methodologies used, discussing the results for both transmission and distribution networks, and providing insights into the broader implications for policy and regulatory frameworks.

Using changes in incentive regulation policies from 1990 to 2020 and DEA techniques, they find consistently slow TFP growth of around 1% p/a in the electricity distribution market. Key findings from the study suggest that the incentive regulation has contributed to improvements in productivity within the electricity networks. The authors highlight the positive association between incentive structures and the adoption of environmentally sustainable practices, indicating that operators respond to regulatory incentives by incorporating environmentally friendly technologies.

Crowley, N., & Meitzen, M. (2021). Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities. Utilities Policy, 72, 101275.

This empirical study examines the impact of price cap regulation versus traditional Rate of Return (ROR) regulation on utility price escalation, using evidence from Canada. It finds that utilities regulated under price caps experienced slower average price escalation compared to those under ROR regulation. A detailed analysis comparing electric distribution utilities in Alberta and Ontario with those in the United States further supports these findings. Alberta, after switching from ROR to price cap regulation, and Ontario, operating under price caps, both showed lower average annual price increases than U.S. utilities under ROR regulation. However, the statistical significance of these differences varied, with Alberta's price cap utilities showing a statistically significant lower price escalation compared to the U.S. counterfactual.

Regression analysis, controlling for factors like firm size and capital additions, indicated that rates under price cap regulation in Ontario and Alberta increase less for every dollar compared to traditional ROR regulation in the United States. While these findings do not conclusively prove that price caps cause slower price escalation, they suggest a correlation that aligns with similar studies in the telecommunications industry and UK electric utilities, which also found lower prices associated with price-cap regulation.

The study underscores that the observed slower price escalation under price caps could be influenced by various factors, not necessarily due to increased efficiency by the firms. It also highlights that the frequency of rate cases under any regulatory regime could affect annual price changes. While the study suggests that consumers may benefit from lower bills under price cap regulation, it does not assess the impact on service quality or company earnings, leaving these areas for future research.

Rauschkolb, N., Limandibhratha, N., Modi, V., & Mercadal, I. (2021). Estimating electricity distribution costs using historical data. Utilities Policy, 73, 101309.

This paper addresses the importance of considering distribution system expenses in the context of increasing electrification for economy-wide decarbonization. While previous studies have often overlooked these costs or used simplified models, this study utilizes detailed historical data from FERC Form 1 to analyze the determinants of electric distribution system expenses. The study focuses on annual capital investments and operations and maintenance (O&M) expenses for 101 major investor-owned utilities (IOUs) in the United States over eight years. It employs econometric methods to examine how utility costs vary based on factors such as the growth rate of distribution system capacity, the proportion of assets installed underground, customer density, and sales to residential customers. Based on historical system peaks, the study estimates that load growth contributes less than 10% to distribution capital costs for a typical utility with an annual capacity growth rate of 1%–3%. Additionally, a 5% growth rate from 2021–2035 would nearly double distribution capacity while increasing the average distribution cost by only about $1/MWh (0.1 cents/kWh) compared to the zero-growth scenario. These findings underscore the potential implications of load growth on distribution costs. The analysis also suggests that many of the distribution system upgrades required to accommodate widespread electrification of heating and transportation can be achieved without significantly raising costs for consumers. Additionally, there is significant variation in distribution system costs across different regions and utilities, indicating that some areas may find electrification more economically feasible than others.

Badunenko, O., Cullmann, A., Kumbhakar, S. C., & Nieswand, M. (2021). The effect of restructuring electricity distribution systems on firms' persistent and transient efficiency: the case of Germany. The Energy Journal, 42(4).

This study focuses on German electricity distribution companies, estimating an input distance function that considers both persistent and transient inefficiency. They disentangle these effects using the four-component stochastic frontier model. The research reveals that overall inefficiency is predominantly driven by the persistent component, which has structural and long-term characteristics. DSOs (Distribution System Operators) in East Germany exhibit lower persistent inefficiency, indicating higher persistent efficiency, a result of the restructuring process post-German reunification. The transient component contributes to inefficiency to a lesser extent, suggesting relatively high transient efficiency among all DSOs, irrespective of their location. The study concludes that the regulatory scheme in place successfully incentivizes efficient production and cost structures, particularly addressing transient inefficiency. However, persistent inefficiency remains a challenge, indicating potential for further improvements in the sector. The findings suggest that additional restructuring, particularly of western DSOs, could be considered. Identifying effective regulatory or policy instruments to target structural inefficiency is left for future research. The analysis underscores the importance of disentangling both types of inefficiency to identify improvement potentials and determine factors influencing short-term and long-term efficiency.

Senyonga, L., & Bergland, O. (2018). Impact of high-powered incentive regulations on efficiency and productivity growth of Norwegian electricity utilities. The Energy Journal, 39(5), 231-256.

The study discusses the impact of regulatory transitions in the Norwegian electricity industry over the last 25 years, focusing on efficiency and productivity growth. After the restructuring in 1990, the industry adopted various regulatory models, including cost-plus, rate-of-return, incentive regulation, and yardstick competition. The goal was to incentivize cost reduction and effective network development. The study hypothesizes that the transition to yardstick competition regulation, implemented in 2007, is associated with positive efficiency and productivity growth.

The study's objective is to empirically examine whether the transition to high-powered yardstick competition regulation corresponds to higher efficiency and productivity growth. It analyzes technical efficiency, total factor productivity growth (TFPG), and decomposes TFPG into technical efficiency change, technical change, and scale change for 121 utilities from 2004 to 2012.

The research contributes to existing literature by using a parametric stochastic frontier analysis (SFA) approach, addressing observed and unobserved heterogeneity. The study differs from previous ones by covering periods with both yardstick competition and incentive-based regulatory regimes. It concludes by discussing the implications of the findings and the limitations of the study.

Bjørndal, E., Bjørndal, M., Cullmann, A., & Nieswand, M. (2018). Finding the right yardstick: Regulation of electricity networks under heterogeneous environments. European Journal of Operational Research, 265(2), 710-722.

This paper discusses the limitations of basic nonparametric benchmarking methods, such as data envelopment analysis (DEA), in differentiating between managerial inefficiency and challenging operational environments. Specifically focusing on revenue cap regulation in the energy sector, the paper highlights the need to compensate firms for difficult operational conditions but not for managerial inefficiency. The paper proposes a conditional DEA benchmarking model for electricity distribution and compares it to an unconditional model and other variants, including the existing two-stage model used by the Norwegian regulator.

The study utilizes a dataset of 123 Norwegian electricity distribution firms to demonstrate how the proposed conditional benchmarking method can estimate managerial inefficiency effectively. The results indicate that conditional benchmarking methods not only affect peer selection and aggregate efficient cost but also lead to a reallocation effect influencing the relative profitability of firms and customer prices. The conclusion suggests that using conditional benchmarking methods may offer a fairer basis for setting revenue caps in the context of revenue cap regulation and nonparametric benchmarking for comparing decision-making units in diverse operational environments.

Dimitropoulos, D., & Yatchew, A. (2017). Is productivity growth in electricity distribution negative? An empirical analysis using Ontario data. The Energy Journal, 38(2).

This paper explores the productivity trends in the electricity distribution sector across Ontario, Canada from 2002 to 2012. The study employs two distinct methodologies to estimate productivity growth: an index-based approach and an econometric cost-based approach. The analysis of 73 Ontario electricity distributors reveals a productivity growth estimate of approximately -1% per year. This finding suggests a significant reversal from the traditionally positive productivity growth estimates reported in earlier periods. This indicates that the electricity distribution sector in Ontario has experienced a decline in productivity growth during the study period.

The importance of this study lies in its contribution to understanding the productivity dynamics in the electricity distribution industry, an area facing upward cost pressures worldwide. By providing empirical evidence of negative productivity growth in Ontario's electricity distribution, the paper challenges prevailing assumptions and highlights the need for further research into the factors driving this trend. The methodology and findings of Dimitropoulos and Yatchew's research offer valuable insights for policymakers, industry stakeholders, and researchers interested in energy economics and the operational efficiency of electricity distribution networks.

Agrell, P. J., & Brea-Solís, H. (2017). Capturing heterogeneity in electricity distribution operations: A critical review of latent class modelling. Energy Policy, 104, 361-372.

This article examines the application of latent class models[132] in benchmarking electricity distribution operations, highlighting the challenge of accounting for heterogeneity within the sector. It reviews previous studies that use latent class models to classify decision-making units based on technology, revealing that these models often assume stationary classes without outliers. The study applies these models to Swedish electricity distributors, finding significant class movement and questioning the robustness of latent class modeling as a regulatory tool. It contrasts parametric findings with non-parametric outlier detection methods, suggesting a cautious approach to adopting latent class models for regulatory benchmarking due to their potential limitations in accurately capturing operational heterogeneity.

Kumbhakar, S. C., & Lien, G. (2017). Yardstick regulation of electricity distribution—disentangling short-run and long-run inefficiencies. The Energy Journal, 38(5), 17-38.

This paper focuses on the application of yardstick regulation to electricity distribution. The authors' objective is to disentangle short-run and long-run inefficiencies using data from Norwegian electricity distribution companies over the period of 2000-2013.

The authors define short-run inefficiency as the variability in efficiency that companies can adjust over time, whereas long-run (persistent) inefficiency is conceptualized as constant over time but varying across companies. By controlling both noise and company-specific effects, the study attempts to provide a more nuanced understanding of the efficiency dynamics in the electricity distribution sector. They argue that this differentiation is crucial so that regulators can design more effective performance-based regulatory policies that can accommodate the distinct nature of short-run and long-run operational efficiencies.

The authors conclude that yardstick regulation has significant beneficial impacts on efficiency. They also find evidence of both short-run and long-run inefficiencies, indicating the importance of considering different time horizons when evaluating the effectiveness of regulatory measures. The authors propose that regulators should design different efficiency

[132] Latent class models are useful in situations where the population can be segmented into distinct classes or groups that differ in their performance or behavior. This heterogeneity might not be observable directly but can significantly impact the benchmarking analysis.

benchmarks for different time horizon efficiency measures to target persistently high problem areas.

Shafali, J., Tripta, T., & Arun, S. (2010). Cost benchmarking of generation utilities using DEA: a case study of India. Technology and investment, 2010.

The authors present cost benchmarking of 30 state-owned electric generation companies from 2007-2008. Data Envelopment Analysis (DEA) models with single input and two outputs are applied to measure the efficiency of these companies.

Coelli, T, Rao, P, O'Donnell, C & Battese, G (2005), An Introduction to Efficiency and Productivity Analysis, 2nd Edition.

This is a textbook on efficiency and productivity analysis. It begins explaining informal definitions, an overview of methods and an outline of chapters while addressing the reader's overall economics background. It then goes on to provide a review of production economics, namely production, transformation, cost, revenue, and profit functions. Later, there is discussion on theoretical representations of production technology, output, and input distance functions and how they relate to the measurement of efficiency, as well as how to measure productivity and change in productivity.

The concept of index numbers is introduced as it relates to productivity measurement. Formulas are specified for price index numbers, quantity index numbers, the transitivity property in multilateral comparisons and how to evaluate TFP change. Later there is discussion on various data and measurement issues and how to make valid comparisons over time, as well as avoid errors in editing, managing data, and dealing with errors.

The book then goes on to explain in-depth several techniques which are used by many of the cited papers in this literature review, including Data Envelopment Analysis (DEA) in both constant returns to scale (CRS) and various returns to scale (VRS) specifications, the scale efficiencies and input and output orientations. There is mention of price information, allocative efficiency, non-discretionary variables, environmental adjustment, input congestion, slack treatment, and additional methods. Regarding econometric estimation of production technologies, it is explained how to perform single equation estimation, use equality constraints, test hypothesis, estimate systems, use inequality constraints, Bayesian approaches and simulation methods.

Stochastic Frontier Analysis (SFA) is discussed including the stochastic production frontier, parameter estimation, the prediction of technical efficiency and hypothesis testing. Later there is the implementation of distance functions, cost frontiers, how to decompose cost efficiency, scale efficiency, panel data models, production environment accounting and Bayesian approaches.

Especially relevant is Chapter 11, which outlines the calculation and decomposition of productivity change using frontier methods. The Malmquist TFP Index (frequently used to calculate total factor productivity) is calculated using both DEA and SFA frontier methods.

Yatchew, A. (2000). Scale economies in electricity distribution: A semiparametric analysis. Journal of applied Econometrics, 15(2), 187-210.

This paper focuses on the economics of distributing electricity. Challenges in analyzing distribution include the lack of distinct entities for statistical analysis, differences in accounting practices, and difficulties in separating distribution costs from other production stages. The analysis focuses on 81 municipal distributing utilities in Ontario, Canada and estimates total cost functions for distribution, excluding power costs to focus solely on distribution services. It finds increasing returns to scale, with firms serving about 20,000 customers achieving minimum efficient scale. Larger firms exhibit constant or decreasing returns. Utilities providing additional services show lower costs, indicating economies of scope. The analysis employs variants of the translog cost function, with output entering non-parametrically and other variables entering parametrically. Comparisons with other studies reveal similar findings. For example, in New Zealand and Norway, utilities serving around 30,000 customers achieve optimal size, with larger firms experiencing diminishing returns to scale. Swiss distributors show increasing returns to scale, but their 'large utilities' are smaller than those in other studies. The results suggest that horizontal mergers among distributors may not yield significant scale economies in their core business. However, there could be economies in power procurement, especially as restructuring separates the wires business from electricity supply. Multiple distributors within one jurisdiction could aid regulators in mitigating informational asymmetries, enabling better estimation of best practices through techniques such as production function estimation.

d. Additional Themes

de Sousa, S. M. S., de Martino Jannuzzi, G., & Barroso, P. D. B. (2023). A multiple criteria decision analysis to benchmark projects in low-income communities by the Brazilian energy efficiency program. The Electricity Journal, 36(2-3), 107252.

This paper outlines a methodology for evaluating energy efficiency projects within low-income communities in Brazil, employing a Multiple Criteria Decision Analysis approach that incorporates six energy efficiency indicators. This system ranks projects based on their economic, technical, social, and environmental performance. The analysis of 101 projects carried out between 2008 and 2013 revealed that less than 10% of these projects were rated as excellent, indicating significant room for improvement within the program. This evaluation framework is suggested for annual implementation by the Brazilian Regulatory Agency to monitor and enhance the program's effectiveness.

Clark, R., & Samano, M. (2022). Incentivized Mergers and Cost Efficiency: Evidence from the Electricity Distribution Industry. The Journal of Industrial Economics, 70(4), 791-837.

This paper delves into the impact of incentivized mergers on cost efficiency within the electricity distribution sector. The study meticulously analyzes data from the industry to investigate whether mergers, particularly those encouraged by policy incentives, lead to significant improvements in cost efficiency. The authors leverage a robust methodological framework to assess the pre- and post-merger performance of companies, accounting for various factors that could influence efficiency outcomes.

The paper's findings reveal that incentivized mergers do, in fact, result in notable cost efficiency gains. These improvements are attributed to several factors, including economies of scale, enhanced operational practices, and the elimination of redundant capacities. Furthermore, Clark and Samano explore the regulatory and policy implications of their findings, suggesting that well-designed incentives for mergers can be a potent tool for regulators aiming to enhance efficiency in the electricity distribution industry. The study contributes to the broader literature on industrial organization and regulatory economics by providing empirical evidence on the efficacy of policy instruments designed to encourage mergers to achieve cost efficiencies. The paper concludes that incentivized mergers in Ontario will not lead to increased efficiencies.

Ghasemi, M., Dashti, R., & Amirioun, M. H. (2021). A hierarchical approach to designing an electricity distribution reward-penalty scheme for service quality improvement. International Transactions on Electrical Energy Systems, 31(12), e13202.

This study introduces a three-step model for determining reward-penalty scheme (RPS) for electricity distribution companies (EDCs). The model is dynamic, adjusting the parameters of the RPS based on the investments made by electricity distribution companies (EDCs) and the costs imposed during each regulatory period. The proposed approach is segmented into three distinct stages: (1) determining the RPS parameters for the first regulatory period, (2) developing a decision-making model for RPS, and (3) determining the RPS parameters for subsequent regulatory periods. The proposed model was implemented for Iranian EDCs. Results verified the effectiveness of the proposed model in ensuring system reliability.

The significance of this research lies in its potential to optimize the balance between incentivizing EDCs for quality service delivery and penalizing poor performance. By dynamically adjusting RPS parameters across regulatory periods, the model accounts for the evolving nature of the electricity distribution sector. This hierarchical approach encourages continuous investment in service quality improvements. The application of this model can lead to more efficient and reliable electricity distribution systems, benefiting both the providers and the consumers through enhanced service quality and performance accountability.

Collan, M., Savolainen, J., & Lilja, E. (2022). Analyzing the returns and rate of return regulation of Finnish electricity distribution system operators 2015–2019. Energy Policy, 160, 112677.

This paper investigates the impact of increased electricity distribution prices in Finland since 2015. The study examines the returns to Finnish low-voltage electricity distribution companies, comparing them with returns from three European industry indices and analyzing the distribution of returns within the industry. The paper outlines the Finnish rate of return regulation model, evaluates the level of allowed returns, and proposes four changes to the model. The effects of these proposed changes on the allowed returns are also investigated. This research provides insights into the Finnish electricity distribution sector's regulatory environment and suggests potential adjustments to improve its efficiency and fairness.

Mirza, F. M., Rizvi, S. B.-U.-H., & Bergland, O. (2021). Service quality, technical efficiency and total factor productivity growth in Pakistan's post-reform Electricity Distribution Companies. Utilities Policy, 68, 101156.

This study explores the relationship between service quality, technical efficiency, and total factor productivity (TFP) growth in Pakistan's post-reform Electricity Distribution Companies (DISCOs). This research is significant as it focuses on an essential sector of the economy that can have a profound impact on the overall economic development of the country. The authors employ a two-stage approach to analyze data from 10 DISCOs over the period of 2004-2018. First, they examine the impact of service quality on technical efficiency using a stochastic frontier analysis model. Second, they investigate the relationship between technical efficiency and TFP growth using the Malmquist index.

The findings of the study highlight the importance of service quality in improving technical efficiency and TFP growth in the electricity distribution sector. The authors observe that higher service quality leads to enhanced technical efficiency, indicating that DISCOs that prioritize customer satisfaction and provide reliable and uninterrupted electricity services are more efficient in utilizing their resources.

Furthermore, the study reveals a positive relationship between technical efficiency and TFP growth. It implies that DISCOs that operate more efficiently are likely to experience higher TFP growth, reflecting their ability to achieve higher levels of productivity with the same amount of resources. The research findings have important implications for policymakers and DISCO managers in Pakistan. They underscore the significance of focusing on service quality improvements to enhance technical efficiency and promote economic growth in the electricity distribution sector. By prioritizing customer satisfaction and effective resource management, DISCOs can contribute to the overall development of the country's energy infrastructure.

Yuan, P., Pu, Y., & Liu, C. (2021). Improving electricity supply reliability in China: Cost and incentive regulation. Energy, 237, 121558.

This paper estimates the costs associated with improving electricity supply reliability within Chinese provinces and estimate the cost efficacy of government incentive regulations. Using provincial level panel data from 2012-2018, they measure the shadow price of electricity supply reliability improvements and the cost incurred by firms from incentive regulations.

The paper's estimates show a wide variation in the marginal cost of reliability improvements amongst provinces, but those marginal costs are consistently lower than in developed economies. However, they find that the costs incurred from the incentive regulations are far lower than the marginal cost of actual reliability improvements, leading to insufficient improvements in supply reliability. The authors recommend more customized incentive regimes for individual provinces and firms.

Gwerder, Y. V., Figueiredo, N. C., & Pereira da Silva, P. (2019). Investing in smart grids: Assessing the influence of regulatory and market factors on investment level. The Energy Journal, 40(4), 25-44.

This study explores the determinants of investment levels in smart grid projects within Europe. Their analysis is centered around the investments made by key stakeholders, including Distribution System Operators (DSOs), universities, and technology manufacturers, which cumulatively amounted to 2286 million euros since 2002. Through statistical tests conducted on investment data from 2008 to 2015 across the EU-28, Norway, and Switzerland, the study assesses how the level of distribution sector concentration, the regulatory framework, and market conditions affect the willingness and ability of these stakeholders to finance smart grid projects. This period of analysis includes both before and after significant regulatory changes and market developments in the European energy sector.

The study's findings highlight the critical role of conducive regulatory and market environments in facilitating substantial investments in smart grid technologies, which are essential for the transition to a clean energy future. By providing a detailed examination of the investment patterns and identifying the factors that significantly influence these investments, the paper contributes valuable insights into how policy and market structures can be optimized to support the deployment of smart grids.

Agrell, P. J., & Teusch, J. (2015). Making the Belgian distribution system fit for the energy transition: The case for yardstick competition 1. Reflets et perspectives de la vie économique, 54(1), 157-174.

This paper explores the challenges and opportunities for implementing yardstick competition in the Belgian electricity distribution sector. It addresses the decentralization of regulatory authority to regional levels and the consolidation of Distribution System Operators (DSOs), which complicates the application of yardstick competition. The authors argue for the potential benefits of yardstick competition in promoting efficiency and suggest exploring inter-jurisdictional comparisons and harmonization efforts across regions and possibly with other countries to enhance regulatory effectiveness. The paper concludes by emphasizing the need for innovative regulatory approaches to support the energy transition while ensuring efficient service delivery.

Nepal, R., & Jamasb, T. (2015). Incentive regulation and utility benchmarking for Electricity Network Security. Economic Analysis and Policy, 48, 117–127.

This paper addresses the incorporation of network security costs within incentive regulation frameworks for electricity networks, a relatively unexplored area. It discusses options for integrating network security costs into benchmarking frameworks and explores associated concerns and limitations, such as cost accounting, choice of cost drivers, data adequacy, and benchmarking methodologies. The introduction of incentive-based regulation and efficiency benchmarking in Europe has prompted debates on how these frameworks should adapt to fundamental technical changes and increasing investment needs in the electricity supply industry. With estimates suggesting substantial investments in grid expansions and transitioning to a low-carbon economy, the dynamics of incentive regulation are evolving. The paper advocates an output-oriented approach to incentive regulation which evaluates performance based on the quantity and quality of delivered outputs, including network security. It proposes defining network security to encompass elements like operational reliability, commercial reliability, resource adequacy, and threats from various events. The paper aims to stimulate policy discussions by proposing output metrics for network security and examining benchmarking options and methodologies. It calls for further exploration of the linkages between incentive regulation and network security, emphasizing the need for conceptual and technical integration of network security into incentive regulation frameworks.

Machek, O., & Hnilica, J. (2014). Total Factor Productivity Benchmarking in Incentive Regulation: Evidence from Czech Gas Utilities and Implications for Post-Communist Countries. Available at SSRN 2376137.

The authors analyze the productivity performance of Czech regional gas distribution companies between 2001-2011 under TFP-based benchmarking. The main tool of analysis is the Fisher index and partial factor productivity analysis. Their results suggest that there were long-term data reliability issues among post-Communist countries that made TFP-based tariff setting unreliable. However, they did recommend using the TFP approach as an underlying method for further analysis and tariff setting.

Evans, L., & Guthrie, G. (2012). Price-cap regulation and the scale and timing of investment. The Rand Journal of Economics, 43(3), 537-561.

This paper delves into the impact of scale economies on the regulated firms' investment behaviour and the welfare-maximizing regulation of price and quantity. The authors find that regulated firms tend to invest in smaller, more frequent increments compared to what would be socially optimal. This highlights a distortion in investment that amplifies with the degree of economies of scale. The study further explores how regulators adjust price caps in response to these economies of scale, finding that regulators set lower price caps under moderate economies of scale and higher caps when economies of scale are significant. This nuanced approach aims to balance the incentives for investment against the need to control prices, illustrating the complex interplay between regulation, investment behavior, and economic efficiency.

Moreover, the paper discusses the consequences of additional quantity regulation alongside price caps, demonstrating that while the average cost of building capacity may increase, the price cap itself tends to decrease. This outcome suggests that incorporating quantity controls can further complicate the regulatory environment, affecting not only the scale and timing of investments but also the overall cost-effectiveness of capacity expansion. By examining these dynamics, Evans and Guthrie provide valuable insights into the challenges and intricacies of designing regulatory policies that effectively encourage investment while managing the economic implications of scale economies in regulated industries. Their analysis underscores the importance of carefully considering the scale and timing of investments in regulatory decisions to ensure that such policies contribute positively to both industry efficiency and social welfare.

Suzuki, A. (2012). Yardstick competition to elicit private information: An empirical analysis. Review of Industrial Organization, 40, 313-338.

This paper examines the impact of yardstick competition implemented in the Japanese local gas distribution sector. Theoretical literature suggests that yardstick competition can address both these problems by comparing firms' costs with similar peers, thereby fostering a competitive environment. However, existing empirical studies mainly focus on the effect of yardstick competition on hidden action (moral hazard), examining its impact on firms' post-behavior in cost-effectiveness. This study examines yardstick competition's effect on the hidden information problem, specifically its influence on firms' pre-action incentive for information disclosure—an aspect not extensively explored before. The study estimated a cost function for gas distributors under the assumption of asymmetric information regarding labour efficiency. Using distributional assumptions, it derived parameter values including labour inefficiency and effort levels. The analysis revealed a cost distortion of 3.8–6.4% due to labour inefficiency. This study also compared welfare levels before and after yardstick inspections and discovered that the initial inspection effectively elicited private information from all distributors. However, subsequent individual inspections were ineffective, possibly due to shortcomings in the current penalty system.

Bauknecht, Dierk, Incentive Regulation and Network Innovations, EUI RSCAS, 2011/02, Loyola de Palacio Programme on Energy Policy-https://hdl.handle.net/1814/15481

The document explores the effects of incentive and cost-based regulation on RD&D and innovation within the electricity network sector, emphasizing the need for regulatory frameworks that encourage innovation. It discusses how different regulatory mechanisms, such as price caps and cost pass-throughs, impact the incentives for Distribution System Operators (DSOs) to invest in research and development. The paper suggests that current regulatory practices may not sufficiently incentivize innovation, highlighting the potential for regulatory adjustments to better support technological advancements and efficiency improvements in the electricity distribution network. It advocates for a balanced approach that considers both the benefits and challenges of regulatory interventions, aiming to foster an environment conducive to innovation while ensuring economic efficiency and consumer protection.

Jamasb, T., & Söderberg, M. (2010). The effects of average norm model regulation: The case of Electricity Distribution in Sweden. Review of Industrial Organization, 36(3), 249–269.

The paper investigates the use of engineering norm models in incentive regulation of electricity distribution networks, focusing on the Swedish context. These norm models, adopted in Sweden in 2003, serve as benchmarks for assessing network utilities' performance. The study analyzes data from 138 network concession holders between 2000 and 2007 to assess whether norm models accurately represent real networks and incentivize performance improvement. Results indicate that norm models inadequately represent real networks, and utilities outperforming their norms tend to behave opportunistically. Private utilities exhibit stronger responses to incentives compared to public ones. The study highlights the historical development of incentive regulation models in energy sectors, emphasizing the search for efficient frameworks to regulate natural monopoly utilities, particularly electricity networks. In Europe and beyond, regulators have adopted various incentive regulation regimes, including price and revenue cap models. In Sweden, norm models serve as reasonably efficient benchmarks, resembling yardstick competition principles. However, norm models have faced criticism for their inability to reflect real firms' dynamics, omission of relevant input factors, and potential creation of perverse incentives. The paper assesses the Swedish experience with norm model-based regulation, finding that it did not significantly improve price, cost, or quality performance of electricity distribution utilities. It explores whether norm models accurately represent actual networks and provide utilities with incentives for best practice performance. Methodologically, the study examines the empirical equivalence of norm models and actual networks, testing the influence of cost determinants and comparing benchmark values. It also evaluates the effects of outperforming the benchmark on utility performance. The paper concludes by discussing the implications of norm model-based regulation and its challenges, emphasizing the need for more accurate representation and incentivization mechanisms. It outlines the Swedish system of electricity regulation, presents the methodology used in the study, reports results, and concludes with reflections on the broader implications for electricity distribution regulation.

Lowry, M. N., & Getachew, L. (2009). Econometric TFP targets, incentive regulation and the Ontario gas distribution industry. Review of Network Economics, 8(4).

This paper delves into the intricacies of implementing incentive regulation mechanisms within the Ontario gas distribution industry. The study emphasizes the role of TFP targets in fostering efficiency and productivity in the sector, arguing that well-designed econometric models can effectively predict and set realistic TFP growth rates that align with the capabilities and potential of the industry. The study first presents a price cap mechanism, which has an external standard designed to elicit efficient utility performance. The authors focus on a method for setting the external standard, which is based on industry-level total factor productivity (TFP) when 'peer data' are not readily available. The method is based on an econometric cost model and externalizes the performance target or TFP by combining industry and utility-level data. The authors conclude that the method they present is practical. Their method can also account for structural changes by utilizing estimated values of driver variables to quantify TFP growth departure from the past.

Giannakis, D., Jamasb, T., Pollitt, M., 2005. Benchmarking and incentive regulation of quality of service: an application to the UK electricity distribution networks. Energy Policy 33 (1), 2256–2271

This paper investigates the role of benchmarking and incentive regulation in enhancing service quality within the UK electricity distribution networks. To calculate the technical efficiency of utilities, the study applies a Data Envelopment Analysis technique and Malmquist indices. The study's analysis is grounded in a comprehensive dataset covering various service quality metrics, providing a basis for identifying best practices and setting realistic targets for utilities. The study finds that the cost-efficiency of firms do not exhibit high service quality. Furthermore, efficiency scores of cost-only models are not highly correlated with those of quality-based models. Lastly, the authors show that the accommodation of service quality in regulatory benchmarking is preferably to cost-only approaches.

This research underscores the potential of benchmarking as a regulatory tool to drive service quality improvements in the electricity distribution sector. The findings suggest that incentive-based regulation, underpinned by thorough benchmarking, can effectively motivate utilities to elevate their performance to industry best standards. The study highlights the complexities of implementing such regulatory mechanisms but ultimately demonstrates their value in promoting economic efficiency, competitive market structures, and superior customer service.

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Appendix D Glossary of Technical Terms

- Activity and Program Based Benchmarking (APB)

  APB applies traditional mechanisms of cost benchmarking to sub-units or business areas of electricity system distributors. Examples of more 'granular' cost categories include billing, vegetation management, and line maintenance.

- Data Envelopment Analysis (DEA)

  DEA constructs an 'efficient production frontier' using input and output data on firms. It is a nonstatistical method which does not readily incorporate varying business operating environments.

- Multilateral Total Factor Productivity (MTFP)

  MTFP compares the efficiency of firms to a hypothetical firm which has average outputs, inputs, revenue and cost shares.

- Panel Data Analysis

  Panel data analysis is a collection of statistical methodologies which combines cross-sectional data (e.g., data on multiple firms in a given year) with time-series data (i.e., data over a series of years for each firm). For example, with 50 firms observed over 10 years one would have 500 observations.

- Parametric and Nonparametric Methods

  Parametric methods require assumptions on the functional form of the model. For example, a common assumption is that a relationship is linear or loglinear. Nonparametric methods, on the other hand, do not rely on functional form assumptions.

  - DEA is a nonstatistical nonparametric approach which does not assume that the production frontier follows a specific shape.

  - Nonparametric regression is a statistical approach which fits a model without assuming a functional form, typically by 'smoothing' the data.

- Partial Performance Indicators (PPI)

  PPIs track a single output measure. For example, total cost per customer, total cost per circuit length kilometre, and total cost per megawatt (MW) of maximum demand. PPIs can also be used for benchmarking sub-categories of activities and programs, much like APB.

- Stochastic Frontier Analysis (SFA)

  SFA is a statistical method for the estimation of cost functions. It differs from conventional regression models because the error term consists of two components: one is typically a normal random variable, the second is a non-positive random variable representing technical efficiency. For example, if the second term is negative, this indicates that the firm is exhibiting lower costs given its operating conditions.

- Total Cost Benchmarking (TCB)

  TCB is comprised of a collection of statistical techniques for estimating the total costs of production given a firm's operating environment and business conditions.

- Total Factor Productivity (TFP)

  TFP compares the growth rate of inputs in a production process with the growth rate of the outputs. Productivity growth is defined to be the difference between the growth of outputs and the growth of inputs. The approach does not readily permit the incorporation of the varying business conditions faced by