COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
D/B/A NATIONAL GRID

D.P.U 18-150

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

DIRECT TESTIMONY OF
DR. MARK NEWTON LOWRY

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

MARCH 22, 2019

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 44 East Mifflin St., Suite 601, Madison, WI 53703.

Q. What is your present occupation?

A. I am the President of Pacific Economics Group Research LLC ("PEG"), an economic consulting firm with headquarters in Madison, Wisconsin. Our primary focus is economics of energy utility regulation. Performance-based ratemaking ("PBR") and statistical research on the cost performance of energy utilities are areas of expertise. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Our work on behalf of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity and dedication to sound research methods. Our practice is international in scope and includes numerous projects in Canada. The Ontario Energy Board ("OEB") is a longstanding client that we have helped to become a world PBR leader.

Q. Please summarize your professional experience.

A: I have over thirty years of experience as an industry economist, most of which have been spent addressing energy utility issues. I have presented in testimony results of research I supervised on PBR and the productivity of energy utilities in more than 30 proceedings. My most recent study of the productivity trends of power distributors was published by Lawrence

Berkeley National Laboratory in 2017.[1] I have authored dozens of professional publications on my work and have spoken at many conferences on PBR and performance measurement.

Before joining PEG, I was a vice president at Laurits R. Christensen Associates ("LRCA"), where I prepared research and testimony on energy utility input price and productivity trends. I also spent several years as an assistant professor in an applied economics department at the main campus of the Pennsylvania State University. A copy of my resume is attached as Schedule MNL-1.

Q. Where have you previously testified?

A: I have testified on PBR and/or cost performance before regulatory commissions in Alberta, British Columbia, California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Missouri, Oklahoma, New Jersey, New York, Ontario, Pennsylvania, Québec, Rhode Island, Texas, Vermont, and Washington state.

Q. What is your prior experience as a witness in Massachusetts?

A: I was the witness for Boston Gas Company on productivity and PBR plan design in the first case to establish a PBR plan with an indexed attrition relief mechanism for a Massachusetts energy utility.[2] I have also testified before the Department of Public Utilities ("Department")

[1] Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric* Utilities, for Lawrence Berkeley National Laboratory, July 2017.

[2] D.P.U. 96-50, *Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 944 through 970, filed with the Department on May*

on PBR and productivity issues for Unitil.[3] I filed comments on PBR on behalf of Commonwealth Energy and worked for a coalition of Massachusetts utilities on service quality regulation. Finally, I prepared electric power distributor productivity research for NSTAR Electric that provided the basis for the Company's X factor in an early PBR plan established in settlement.[4]

Q. Please describe your educational background.

A. I attended Princeton University before earning a bachelor's degree in Ibero-American Studies and a PhD in Applied Economics from the University of Wisconsin-Madison.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of the Attorney General ("AGO").

Q. What is the purpose of your testimony?

17, 1996 to become effective June 1, 1996 by Boston Gas Company; and investigation of the proposal of Boston Gas Company to implement performance-based ratemaking, and a plan to exit the merchant function.

[3] D.P.U. 13-90, *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges set forth in Tariffs M.D.P.U. Nos. 229 through 238, and approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on July 15, 2013, to be effective August 1, 2013.*

[4] D.P.U. 05-85, *Petition of Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and NSTAR Gas Company (collectively, the "Companies") for approval by the Department of Telecommunications and Energy of (1) a Joint Motion for Approval of Settlement Agreement and (2) the Settlement Agreement entered into by the Companies with the Attorney General of Massachusetts, the Low-Income Energy Affordability Network and Associated Industries of Massachusetts.*

A. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or "the Company") have filed a petition with the Department for an increase in the Company's base rates. The petition includes a proposal for a five-year PBR plan. The Company's proposed plan is similar to the plan the Department recently approved for NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[5] Under its proposed plan, NGrid's allowed base revenue would be escalated by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.[6]

NGrid's X factor proposal is based on index research and testimony by Dr. Mark Meitzen of LRCA. Here, LRCA used a research methodology similar to the methodology they used in D.P.U. 17-05.[7] My testimony will address the X factor issue. I evaluate the work of LRCA and discuss some general problems with the capital cost specification LRCA used. In addition, I briefly discuss problems with the National Economic Research Associates ("NERA") research which was the foundation for LRCA's study. Next, I propose an alternative X factor that is based on my company's research. An extensive report on PEG's research and X factor issues is attached as Schedule MNL-2. This report is intended to provide the Department with information on RCI design that the Department can use in this and future PBR proceedings.

[5] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[6] Exh. NG-LRK-1, at 5. The Company's PBR Proposal includes seven components: (1) an inflation factor; (2) a "productivity offset" or X-factor formula; (3) a consumer dividend; (4) a Z factor; (5) an earnings sharing mechanism; (6) a plan term; and (7) performance incentive mechanisms and scorecard metrics.

[7] Exh. NG-MEM-1; *see also*, D.P.U. 17-05, *Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism*, Exh. ES-PBRM-1.

III. X FACTOR ISSUES

A. CRITIQUE OF THE LRCA EVIDENCE

Q. Please summarize LRCA's testimony in this proceeding.

A: LRCA's study for NGrid has its origins in power distribution productivity research by NERA. The study employs a monetary approach to the measurement of capital cost called the one-hoss-shay ("OHS") method, which specifies that the quantity of capital resulting from the total value of plant additions in a given year is constant until the plant is retired at the end of its estimated average service life. LRCA's study assumes a 33-year average service life. I have criticized the NERA/LRCA approach to measuring capital cost in several Canadian proceedings.[8]

Using data for the fifteen-year 2002-2016 period, LRCA reported a -0.13% total factor productivity ("TFP") trend for the U.S. power distribution industry and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials, a common practice in Massachusetts regulation. The sum of the resultant -0.95% productivity differential and -0.77% input price differential is **-1.72%**, which LRCA and NGrid have proposed as the base X factor. To this, NGrid proposes to add a 0.40% consumer dividend in years when inflation exceeds 2%. The 0.40% value is based on statistical benchmarking work by Dr. Lawrence Kaufmann of Kaufmann Consulting.

Q. Why did LRCA use the productivity research methods of another consultant?

[8] *See, e.g.*, Alberta Utilities Commission Proceedings 566 and 20414, and Ontario Energy Board Cases EB-2016-0152 and EB-2017-0307.

A. In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare a productivity study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. NERA's study of the productivity trends of U.S. power distributors featured a long sample period starting in 1973, and NERA advocated for an X factor based on results for the *full* sample period. Costs of several customer services were excluded from NERA's study since these services are not provided by Alberta distributors. Another unusual feature of NERA's study was the negative total factor productivity ("TFP") trend of distributors after 2000. This finding runs counter to the results that PEG obtains with methods that we have used in past studies for Massachusetts utilities.

Rather than undertake original productivity research, some utility witnesses in this proceeding embraced the results of NERA's study, but only for the period after 2000. The AUC rejected the recommendations of utility witnesses for negative X factors. Instead, AUC chose a base productivity trend of 0.96% based on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify.[9] The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study, with some modifications, rather than undertaking original studies.[10] Both consultancies based their X factor recommendations on results since 2000. LRCA argued that index research for X factor calibration should be "forward looking" and based on results for a national sample. The witness for LRCA, Dr. Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC

[9] Alberta Utilities Commission, Proceeding 20414.

[10] Alberta Utilities Commission, Proceeding 20414.

once again rejected the recommendations of the utility witnesses and instead approved an X factor of 0.30%. This decision was informed by PEG evidence of a TFP trend of 0.43% for the full sample of U.S. electric power distributors using an alternative capital cost specification.

Q. Has the productivity trend of U.S. power distributors been considered in subsequent PBR proceedings?

A. Yes. NERA subsequently presented an updated version of its power distribution productivity study in Ontario testimony to establish a PBR plan for two merging gas utilities. NERA and the OEB's consultant (PEG) both recommended a 0% base TFP trend for these utilities, which was ultimately approved by the Board.

Even though LRCA did not prevail on the X factor issue in Alberta, Eversource retained them to prepare index research for Eversource's PBR application in D.P.U. 17-05. In its study for Eversource, LRCA's methods remained quite similar to that of NERA. One notable change was LRCA's use of the number of customers as the output index. However, LRCA, like NERA, excluded costs of customer services and administrative and general tasks even though these costs are incurred by Eversource and were included by NERA in earlier research and testimony for Central Maine Power.[11] LRCA also retained NERA's capital cost methods. In addition to a substantially negative productivity differential, LRCA computed a substantially negative input price differential. The Department utilized LRCA's research in D.P.U. 17-05 and sanctioned LRCA's use of OHS but approved a lower X factor than LRCA

[11] Maine Public Utilities Commission, Docket 1999-00666.

recommended.

Recently, in a Québec proceeding to design an RCI for Hydro-Québec Distribution, the Régie de l'énergie considered the X factor issue.[12] PEG was a witness in this proceeding for industrial intervenors. With full knowledge of the Department's decision in D.P.U. 17-05 and of PEG's critique of the NERA/LRCA methodology, the Régie chose a 0.30% base productivity trend.

Q. What is your assessment of LRCA's X factor evidence for NGrid?

A. I have serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, I believe that LRCA, like NERA, used the OHS approach to measuring capital cost incorrectly. The benchmark year adjustment is wrong, and the assumed average service life of distribution assets is too low. Results are very sensitive to the assumed average service life. The average service lives of distribution assets have been rising for years and a 36-year assumption is more realistic. LRCA's input price research is even more problematic than its productivity research. Taken together, LRCA's errors materially suppress the indicated X factor in the Company's favor.

Q. Please explain your reservations about LRCA's input price research.

A. The capital price index that LRCA uses includes capital gains because plant is valued in replacement dollars. This matters because an unusual run-up in electric power distribution

[12] Québec Régie de l'énergie, R-4011-2017.

construction costs, due in part to rising copper prices, occurred during these years that is unlikely to be repeated in the next five years. LRCA's input price index captured this run-up but not the offsetting capital gains. The problem was compounded by LRCA's relatively short sample period. LRCA's treatment of the input price differential runs counter to their stated goal of conducting a forward-looking study. In their recent Ontario testimony, NERA calculated an input price differential using data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[13]

Q. Have you tested the sensitivity of LRCA's results to the problems you discuss?

A. Yes. PEG used LRCA's data but then incorporated an improved OHS specification using a 36 year average service life and a more appropriate input price index. We found that the TFP trends of U.S. power distributors averaged 0.30% from 2003 to 2016 and that the input price trend was only 2.17%. The resulting -0.52% productivity differential and 0.56% input price differential sum to a 0.04% base X factor. The analogous results for Northeastern distributors are a -0.33% TFP trend, a -1.15% productivity differential, and a 0.51% input price differential. These sum to a -0.64% base X factor.

Q. Are you comfortable with LRCA's use of the number of customers as the output index

[13] OEB proceeding EB-2017-0307, Exh. B, Tab 2, at 32 (November 23, 2017).

in its productivity work?

A. Not entirely. I acknowledge that the number of customers is commonly used to measure output in energy distributor productivity studies, including several studies that I have directed. The number of customers has also been used as the scale escalator in some RCI formulas. However, I explain at some length in Section 3.1 of my report (Schedule MNL-2) that, contrary to the unpersuasive representations of LRCA, the number of customers need not be used as the sole output measure in an RCI calibration study. Multidimensional scale indexes can instead be used, with weights based on econometric research on the cost impact of various candidate scale variables. Such indexes would likely assign a large weight to customer growth but might include other scale variables such as peak demand. Peak demand rose more rapidly than the number of customers served for many U.S. power distributors during the last fifteen years.

Q. Do you have other concerns with LRCA's work?

A. Yes, although these problems do not significantly influence LRCA's results. Here are some examples.

- LRCA includes pensions and benefits in its study even though these are slated for tracker treatment in the NGrid plan.
- LRCA treated pension and benefit expenses as material and service costs rather than labor costs;
- Some mergers were not correctly handled; and
- The sample size is unnecessarily small. This apparently is due to LRCA's reliance on the

NERA data. The capital quantity calculations require many years of plant value data. As NGrid states in response to information request DPU-NG-13-8:

> Dr. Meitzen originally obtained the dataset from the NERA study that was submitted in Alberta. FERC only posts Form 1 data on its website back to 1994. Thus, the required capital data back to 1964 for companies not in the original NERA sample would require extensive effort to compile.[14]

B. GENERAL CONCERNS ABOUT ONE HOSS SHAY

Q. Please discuss some of the general disadvantages of OHS.

A. In my view, the geometric decay ("GD") approach to calculating utility capital cost is a more appropriate approach than OHS for X factor calibration research. Under GD, the quantity of capital from plant additions is assumed to decline gradually over time. Capital cost trends using GD reflect depreciation in a manner similar to that resulting from the capital cost methods used in Massachusetts to calculate utility revenue requirements. This matters since the RCI is designed to adjust allowed revenue between rate cases.

The LRCA/NERA approach to OHS, in contrast, abstracts from depreciation. Even though NGrid acknowledged in response to information request AG-23-8 that assets that exhibit a OHS service flow pattern depreciate in value, neither the capital quantity index nor the capital service price reflect it. [15]

[14] Exh. DPU-NG-13-8.

[15] Exh. AG-23-8.

Here are some other general concerns I have with the OHS method:

- OHS formulas are more difficult to code, review, and understand. The sensitivity of results to the average service life assumption is one of many problems.
- Studies have found that prices in many used asset markets are inconsistent with the OHS assumption.[16]
- Many electric power distributor assets do not deliver a constant flow of services. Even if they did, the OHS specification of a constant service flow does not make sense for heterogeneous groups of assets with varied service lives like those typically used in LRCA's study. The following quote from a capital cost manual published by the Organization of Economic Cooperation and Development explains this point:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[17]

16 For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

17 OECD, *Measuring Capital OECD Manual 2009,* Second Edition, at 12.

For these and other reasons, the OHS approach to measuring capital cost is less widely used than GD in productivity studies.

Q. Which approach to measuring capital cost is more widely used in X factor calibration studies?

A. To date, the GD approach has been most widely used in studies of this kind. For example, it is frequently used today in productivity and other statistical cost research by consultants to Ontario energy utilities. GD was also used in the great majority of LRCA's productivity studies before Dr. Meitzen started testifying for power distributors. Dr. Meitzen himself has used GD in numerous productivity studies that he prepared for telecommunications utilities and has enumerated several advantages of GD in reports that he authored. For example, this quote supporting GD, from a report Dr. Meitzen coauthored for the Peruvian telecom regulator OSIPTEL, reprises several of the points that I have already made:

> Productivity studies that are based on net stocks of capital generally employ this [geometric decay] assumption, since their net stocks are based on straight-line depreciation assumptions. The geometric pattern is based on the assumption that the productivity of an asset decreases at a constant percentage rate… Numerous productivity studies have employed this assumption, including our previous studies of the U.S. telephone industry. Hulten also notes that most empirical studies of depreciation support the use of the geometric function over the one-hoss shay or straight-line function.
>
> There are two sources for the decline in the efficiency of an asset as it ages. First, the asset may produce fewer services as it ages. Second, an asset may require more labor or materials (e.g., more maintenance) to provide the same level of services. For a cohort of assets (i.e., assets of the same asset class and the same vintage) there is a third source of efficiency decline, namely the retirement of assets. Retirement of a cohort of assets will generally occur over a number of years. As individual assets are removed from production, their contribution to the cohort will also be removed, and the overall productivity of the cohort will be reduced.[18]

[18] L. R. Christensen, M. Meitzen, P. E. Schoech, L. D. Kirsch, C. A. Herrera, and S. M. Schroeder *Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation*, Report to OSIPTEL, May 1999, p. 68.

Q. If GD makes sense for telecommunications, how does Dr. Meitzen defend his use of the OHS method in his three power distribution productivity studies?

A. Dr. Meitzen claims in response to information request AG-23-3(c) that rapid technological change in telecommunications has caused some assets to be retired prematurely, even if they were previously yielding a constant service flow.[19]

Q. Does this make sense?

A. This is one argument for using GD in telecommunications productivity research. However, Dr. Meitzen enumerates several others. A substantial part of the business of local telecommunications exchange carriers consists of wires and poles. Moreover, technological obsolescence is sometimes observed in the business of a power distributor as well. For example, there has been rapid change in the last decade in technologies for metering, billing, pricing, and customer services. New smart grid technologies are frequently discussed in the trade press and considered for use in Massachusetts.

I should also note that many of the other arguments that Dr. Meitzen made in support of GD in the OSIPTEL report also apply to power distributors. For example, the service lives in a cohort of annual distribution plant additions are varied. Moreover, the cost of maintaining some distribution assets rises as they age. NGrid stated this in response to information request AG-15-3(f):

> The question asks whether keeping distribution plant in "good working order …" tends to require increasing *real* maintenance costs. It is not discernible whether the question intended to distinguish *real* from *nominal* expenditures. However, for assets that require regular maintenance, the costs associated with

[19] Exh. AG-23-3(c).

> keeping the plant in good working order tend to increase over the life of the asset, until it is retired. National Grid's experience, as shared with the sponsor, is that maintenance costs can increase as assets age for some specific assets.[20]

C. ORIGINAL PEG RESEARCH

Q. Have you undertaken an independent indexing study for the AGO using PEG's preferred methods and data?

A. Yes. To provide the Department with better information, PEG used a larger sample of distributors than LRCA and a longer sample period, which included 2017, the most recent year for which data are currently available. PEG calculated candidate base X factors using two alternative methods: GD and the Kahn Method. Using the GD approach to capital cost, the TFP growth of all utilities in our sample averaged 0.33%, the productivity differential was -0.65%, and the input price differential was -0.06%. The analogous results for Northeastern distributors are a 0.36% TFP trend, a -0.62% productivity differential, and a -0.12% input price differential.

Q. Please explain the Kahn Method.

A. This method for setting X factors was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. The Kahn method has been used several times by the FERC to set the X factors in PBR plans for interstate oil pipelines. It is easy to use and employs a traditional approach to calculating capital cost. The X factor resulting from such a calculation reflects the input price and productivity differentials of utilities without having to calculate them.

[20] Exh. AG-15-3(f).

Applying the Kahn method to NGrid, PEG calculated trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting. We then solved for the value of X, which caused the trend in distributor cost to equal the trend in a particular kind of RCI on average. The generic RCI used the gross domestic product price index ("GDP-PI") as the inflation measure. The analysis excludes costs that are likely to be addressed by trackers and riders in NGrid's plan. As discussed further in our report (Schedule MNL-2), we calculated a base X factor for NGrid using the Kahn method using national data and arrived at a value of -0.41%. The analogous result using Northeast data was -0.45%.

D. X FACTOR RECOMMENDATIONS

Q. What conclusions do you draw concerning the base X factor?

A. Our review of the assembled productivity evidence reveals the following facts:

Using PEG's upgraded OHS capital cost methodology and LRCA's data, the productivity differential for the full U.S. sample is -0.52% and the inflation differential is 0.56%. These indicate a base X factor of **0.04%.** The indicated base X factor using corrected OHS and Northeast data is **-0.64%.**

Using the GD capital cost methodology, PEG's own data, and research results for a larger sample and a longer sample period produces a productivity differential of -0.65% and an input price differential of -0.06%. This indicates a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**

The indicated base X factor using the Kahn method is **-0.41%.**

Other plan provisions should also be considered when choosing the X factor:

- The stretch factor is an important part of customer benefits from any PBR plan. A 0.40% value has been recommended for a reason: NGrid has been spending large sums on capex in recent years and its cost of service is, at least temporarily, high. The proposed 0.40% stretch factor is contingent on 2% inflation. This provision is rare in PBR plans. Productivity growth does not vary with inflation. Inflation has been sluggish in recent years and this may continue.
- NGrid is requesting tracker treatment for certain grid modernization and electric vehicle capital expenditures ("capex") that are now and will in the future be incurred by the utilities sampled in productivity studies. These kinds of capex will be incurred by the utilities used in future X factor calibration studies. If PBR continues, there is then a danger that customers will pay twice for the same capital expenditures.
- NGrid has also asked for higher vegetation management expenses to be tracked. This is also unusual in PBR plans but may be defensible if an increase in service quality is expected.
- NGrid is not requesting a scale escalator for its RCI growth formula. However, our analysis has shown that expected customer growth is not an implicit stretch factor. Trends in other dimensions of scale are also pertinent. Peak demand growth is widely recognized to be a major driver of power distribution cost, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, and assuming that the RCI does not include an explicit scale escalator as proposed, PEG recommends a base X factor of **-0.60%** for NGrid.

Further, we believe that the Department should recognize that there are a range of methodologies that warrant consideration when choosing X factors. The 0.40% additional stretch factor should not be contingent on inflation. Therefore, NGrid's total X factor should then be -0.20%.

Q. Does this conclude your direct testimony?

A. Yes.

RESUME OF
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March 2019

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Education High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of a consulting firm in the field of utility economics. Leads internationally recognized practice performance-based regulation and utility performance research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.
8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.
12. Workshop on PBR for Electric Utilities. Southern Company Services, 1991.
13. Economics of Electric Revenue Adjustment Mechanisms. Niagara Mohawk Power, 1991.
14. Sales Promotion Policies of Gas Distributors. Northern States Power-Wisconsin, 1991.
15. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in PBR. Southern California Gas, 1991.
16. Cost Performance Indexes for Gas and Electric Utilities for Use in PBR. Niagara Mohawk Power, 1991.
17. Efficient Rate Design for Interstate Gas Transporters. AEPCO, 1991.
18. Benchmarking Gas Supply Services and Testimony. Niagara Mohawk Power, 1992.
19. Gas Supply Cost Indexes for Incentive Regulation. Pacific Gas & Electric, 1992.

20. Gas Transportation Strategy for an Arizona Electric Utility. AEPCO, 1992.
21. Design and Negotiation of a Comprehensive Benchmark Incentive Plans for Gas Distribution and Bundled Power Service. Niagara Mohawk Power, 1992.
22. Productivity Research, PBR Plan Design, and Testimony. Niagara Mohawk Power, 1993-94.
23. Development of PBR Options. Southern California Edison, 1993.
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5. Electric Council of New England, Boston MA, November 1989
6. Electric Power Research Institute, Milwaukee WI, May 1990
7. New York State Energy Office, Saratoga Springs NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
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Journal Referee

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American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
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PBR Plan Design for National Grid in Massachusetts

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1. Introduction and Summary

1.1. Introduction

On November 15, 2018, National Grid USA filed an application with the Massachusetts Department of Public Utilities ("Department") concerning rates for the power distributor services of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or the "Company"). The Company's petition proposes a five-year Performance-Based Ratemaking ("PBR") plan which includes a change in base distribution rates, followed by a PBR mechanism ("PBRM") to adjust rates annually for four years.[1] The proposed plan is similar to that which the Department recently approved for power distributor services of NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[2] If approved by the Department, NGrid's plan would allow the Company's base revenue to escalate by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.

The X factor is a key issue in PBR plans of this type. NGrid's X factor proposal is based on input price and productivity research and testimony by Dr. Mark Meitzen of the consulting firm Laurits R. Christensen Associates ("LRCA"). Dr. Meitzen used a research methodology like the one he employed in testimony for Eversource.[3]

NGrid is one of the largest power distributors in the Commonwealth. LRCA's research supporting the X factor approved for Eversource was controversial and vigorously contested.[4] These considerations increase the importance of a careful appraisal of NGrid's PBR proposal and supportive index research. Controversial technical work and PBR provisions should be highlighted and, where warranted, challenged to avoid undesirable precedents for the NGrid and other Massachusetts utilities in the future.

Pacific Economics Group Research ("PEG") is the leading North American consultancy in the field of energy utility input price and productivity research. PEG has consulted with regulators, utilities,

[1] Exh. NG-PBRP-1, at 50.

[2] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[3] *See generally*, D.P.U. 17-05, Exhs. ES-PBRM-1; ES-PBRM-Rebuttal-1.

[4] *See, e.g.*, D.P.U. 17-05, Exhs. AG/DED-1; ES-AG/DED-Surrebuttal-1.

consumer groups and government agencies; giving PEG a reputation for objectivity and advocacy for sound regulations. Our personnel have testified several times for utilities in Massachusetts and other New England states. The Attorney General of Massachusetts ("AGO") has retained PEG to prepare analysis and commentary on LRCA's research and testimony and certain aspects of NGrid's PBR proposal.

Following a summary of PEG's findings, Section 2 of this report reviews pertinent background information regarding NGrid's proposed PBR plan. In Section 3, the nature of productivity research and its role in RCI design are discussed. In Section 4, PEG critiques LRCA's methodologies and findings using alternative methods. Section 5 presents results of original X factor calibration research that PEG prepared for the AGO. Finally, Section 6 discusses the stretch factor and PEG's X factor recommendations. Appendices address some of the more technical issues raised in the report in more detail.

1.2. Summary

X Factor

PEG has serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, we believe that LRCA has used the one-hoss-shay ("OHS") approach to measuring capital cost incorrectly and that their errors materially suppress the indicated X factor in the Company's favor. With an improved OHS approach and LRCA's data, PEG finds using national data that the total factor productivity ("TFP") trends of U.S. power distributors averaged 0.30% from 2003 to 2016. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor would be **0.04%** and not the **-1.72%** that LRCA reports. Further, the OHS method has general disadvantages in X factor calibration, which are discussed below.

PEG also calculated a base X factor using two alternative methods: geometric decay ("GD") and the Kahn Method. Our research used a larger sample of distributors than LRCA did and a longer sample period that included 2017. Using GD, the TFP growth of all utilities in the national sample averaged 0.33%. The productivity differential was -0.65% and the input price differential was -0.06%. These findings indicate a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.** The base X factor using the Kahn method and national data was **-0.41%.** The base X factor using the Kahn method and Northeast data was **-0.45**%. The stretch factor would be operative only if inflation exceeds 2%.

Other plan provisions also merit consideration in the choice of an X factor. The stretch factor is contingent on inflation exceeding 2%. An uptick in vegetation management expenses would be tracked. A tracker treatment is proposed for certain grid modernization and electric vehicle capital expenditures ("capex"). These kinds of capex will raise the cost of U.S. distributors in productivity studies used to set X factors.

Based on the assembled evidence and assuming that the RCI as proposed does not have an explicit scale escalator, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The stretch factor would apply whether or not inflation exceeded 2%.

2. Background

NGrid's proposed PBR plan is essentially a multi-year rate plan ("MRP") that includes an RCI for allowed revenue escalation and a performance metric system. The term of the plan would be five years. Initial rates would be established in a general rate case. Allowed base revenue would then be escalated for four years by an RCI with an inflation minus a productivity offset (i.e., I – X) formula. A decoupling mechanism would ensure that actual revenue would track allowed revenue closely.

The RCI formula would feature the gross domestic product price index ("GDP-PI") as the inflation measure. The proposed -1.32% X factor would be the sum of a -1.72% base productivity offset and a 0.40% consumer dividend would be added if inflation exceeds 2%. The base productivity offset would be the sum of a productivity differential and an inflation differential. Thus, the input price and productivity trends of power distributors are both issues in this proceeding.

Some costs would be scheduled for tracker treatment. These would include pension and benefit and demand-side management ("DSM") expenses. Supplemental revenue would be available for an electric vehicle infrastructure program and grid modernization. A Z factor provision would adjust revenue for unforeseeable, exogenous cost changes.[5]

The grid modernization tracker, as proposed, addresses the cost of investments pre-approved by the DPU in grid modernization plan proceedings and the Company's proposed storage program. A grid modernization program was approved in 2018 to allow NGrid to invest in various technologies including Volt/Var Optimization, advanced distribution automation, and feeder monitors over a 3-year term. The Company is required to file a new grid modernization plan during the MRP term. It is unclear how much grid modernization capex will be approved for tracking during the latter years of the term. The storage program has been proposed in this proceeding. If approved, the Company would build several storage projects.

NGrid has another cost tracker that addresses the capital and operation and maintenance ("O&M") costs associated with EV deployment. The Company received approval of Phase 1 of the deployment in 2018 and has proposed Phase 2 of deployment in this proceeding. For Phase 2, the

[5] Exh. NG-LRK-1, at 7.

Company proposes to deploy charging infrastructure, provide rebates and discounts to customers, provide fleet advisory services, market and evaluation the plan, and undertake research and development.

The Company also proposes to continue to rely on an existing vegetation management tracker to fund the incremental O&M costs of its enhanced vegetation management pilot. The current program was approved in D.P.U. 17-92 for a 4-year period beginning April 1, 2019.[6] The existing program allows the Company to perform targeted vegetation management of worst performing circuits with enhanced clearances including condition assessment and outreach with affected individuals. In the current proceeding, the Company has proposed to expand the vegetation management provision to address the incremental O&M costs of switching to a four-year pruning cycle, as well as to expand the removal of ash trees damaged by the emerald ash borer and oak trees damaged by gypsy moths.

The Company has also proposed to continue its storm fund replenishment tracker to address incremental O&M costs of major storms. This fund allows NGrid to receive funding, net of a deductible per storm, to address major storm costs. To help stabilize the fund, costs of extreme storms would continue to be addressed separately.

The Company has also proposed to include a Z factor, referred to as an exogenous cost adjustment. In order to qualify as an exogenous cost, an event must be beyond the Company's control; arise from a change in accounting requirements, regulatory, judicial, or legislative directives or enactments; be unique to the electric distribution industry rather than the general economy; and exceed a materiality threshold. The materiality threshold would be $3 million per event for 2020, and the Company has proposed to escalate the threshold for each year of the plan by the growth in GDP-PI. Two specific types of events would be explicitly eligible for exogenous cost treatment: severe storms and any excise tax on high-cost employer medical insurance plans under the Patient Protection and Affordable Care Act.

[6] D.P.U. 17-92, *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval for an Enhanced Vegetation Management Pilot Program and the recovery of associated costs through an Enhanced Vegetation Management Pilot Program Provision, M.D.P.U. No. 1343* (August 13, 2018).

A tiered earnings sharing mechanism ("ESM") would share surplus earnings above a 200 basis point deadband above the allowed return of equity.[7] An efficiency carryover mechanism was considered by NGrid but not proposed.

The performance metric system would include performance incentive mechanisms ("PIMs") for peak load reduction, transportation electrification, EV program cost containment, and "customer ease" as well as the PIMs that are already operational for service quality and DSM. Three new "scorecard metrics" without PIMs are also proposed.[8] The proposal also encompasses a Climate Mitigation and Adaptation Plan.[9]

[7] Exh. NG-LRK-1, at 7.

[8] Exh. NG-LRK-1, at 8-10.

[9] Exh. NG-NG-PBRP-1, at 104-105.

3. Principles for X Factor Calibration

3.1. Productivity Research and its Use in Regulation

This section of the report considers some technical and theoretical issues that arise in input price and productivity research to support X factor choices in PBR plans. Issues are emphasized which arise in our appraisal of NGrid's PBR proposal and the input price and productivity research presented by LRCA.

Productivity Indexes

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The growth in a productivity index is the difference between the growth in an output index ("Outputs") and the growth in an input quantity index ("Inputs").

growth Productivity = growth Outputs – growth Inputs. [1]

That is, productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. Partial factor productivity indexes measure productivity in the use of certain inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple inputs. In Massachusetts, these are usually called *total factor* productivity indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, then the growth in each output dimension which is itemized is measured by a subindex, and growth in the summary index is a weighted average of the growth in the subindices.

In designing an output index, choices concerning subindices and weights should depend on the way the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[10] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$growth\ Productivity^R = growth\ Outputs^R - growth\ Inputs. \qquad [2a]$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[11] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \qquad [2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[12] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important productivity growth driver is economies of scale. These economies are realized in the longer run if cost tends to grow less rapidly than operating scale. Incremental scale

[10] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[11] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[12] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

economies (and thus productivity growth) will typically be lower the slower is output growth.[13]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher its current inefficiency level is.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses due to maturing trees will cause operation and maintenance ("O&M") and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since:

$$\begin{aligned} \text{growth } TFP^R &= \text{growth } Outputs^R - \text{growth } Inputs + (\text{growth } Outputs^C - \text{growth } Outputs^C) \\ &= (\text{growth } Outputs^C - \text{growth } Inputs) + (\text{growth } Outputs^R - \text{growth } Outputs^C) \\ &= \text{growth } MFP^C + (\text{growth } Outputs^R - \text{growth } Outputs^C). \qquad [3] \end{aligned}$$

Relation [3] shows that the growth in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

[13] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow.

The output differential is sensitive to changes in external business conditions such as those that drive system use. For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of RCIs. Consider the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C.^{14} \qquad [4]$$

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form:

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility} \qquad [5a]$$

where

$$X = \overline{TFP^C} + \textit{Stretch}. \qquad [5b]$$

Here X, the “X factor,” reflects a base productivity growth target (“$\overline{TFP^C}$”) that is typically the trend in the TFP^C of the regional or national utility industry or some other peer group. Notably, a cost-based output index should be used in the supportive productivity research. Further, a “stretch factor” is often added to the formula, which slows price cap index growth in a manner that shares the financial benefits of performance improvements which are expected under the PBR plan with customers. Since the X factor often includes *Stretch* it is sometimes said that the productivity research has the goal of “calibrating” (rather than solely determining) X.

An alternative basis for an RCI can be found in index logic. It can be shown that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index:

[14] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Input Quantities} \quad [6]$$

Then,

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Scale}^C - (\textit{growth Scale}^C - \textit{growth Input Quantities})$$
$$= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C \quad [7]$$

For gas and electric power distributors, the number of customers served is a sensible scale escalator for an RCI. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost. A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote DSM. This is an argument for excluding these variables from an RCI scale escalator.

Relation [6] can then be expanded to obtain the following result:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Input Quantities} + (\textit{growth Customers} - \textit{growth Customers})$$
$$= \textit{growth Input Prices} - (\textit{growth Customers} - \textit{growth Inputs}) + \textit{growth Customers}$$
$$= \textit{growth Input Prices} - \textit{growth TFP}^N + \textit{growth Customers}$$

where TFP^N is a TFP index that uses the number of customers to measure output. This result provides the rationale for the following revenue cap index formula

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Customers} \quad [8a]$$

where

$$X = \overline{TFP}^N + \textit{Stretch}. \quad [8b]$$

An equivalent formula is:

$$\textit{growth Revenue} - \textit{growth Customers}$$
$$= \textit{growth } (\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \quad [8c]$$

This is sometimes called a "revenue per customer" index and, for convenience, this expression will be used to refer to RCIs which conform to either [8a] or [8c].

Inflation Issues

If a macroeconomic inflation index, such as GDP-PI, is used as the inflation measure in a RCI, then Relation [4] can be restated as:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Scale} \\ &\quad + \textit{growth GDPPI} - \textit{growth GDPPI} \\ &= \textit{growth GDPPI} - [\textit{growth Productivity} + (\textit{growth GDPPI - growth Input Prices})] \\ &\quad + \textit{growth Scale}. \end{aligned} \qquad [9]$$

Relation [9] shows that cost growth depends on GDP-PI inflation, growth in operating scale and productivity, and on the difference between GDP-PI and utility input price inflation. The difference between GDP-PI and utility input price inflation may be termed the "inflation differential."

The GDP-PI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[15] It can then be shown that the trend in the GDP-PI is well-approximated by the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{growth GDPPI} = \textit{growth Input Prices}^{\textit{Economy}} - \textit{growth Productivity}^{\textit{Economy}}. \qquad [10]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{TFP}^{C} - \overline{TFP}^{\textit{Economy}}) + (\overline{\textit{Input Prices}}^{\textit{Economy}} - \overline{\textit{Input Prices}}^{\textit{Industry}})]. \qquad [11]$$

Here, the first term in parentheses is called the "productivity differential." It is the difference between the TFP trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

Relation [11] is notable because it has been the basis for the design of several approved X factors in PBR. This approach has been especially popular in New England regulation.[16]

3.2. Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost specification is critical in research on the productivity trends of energy distributors because the technology of these companies is capital intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

[15] Final goods and services include consumer products, government services, and exports.

[16] This approach has been approved in Massachusetts on several occasions. *See, e.g.*, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, and D.P.U. 17-05.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in TFP research. Capital cost decomposes into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK.^{17} \qquad [12]$$

Capital quantity indexes are constructed by deflating the value of plant additions using an asset price index and subjecting the resultant quantity estimates to a mechanistic decay specification. In research on the productivity of U.S. energy utilities, Handy Whitman utility construction cost indexes have traditionally been used for this purpose.

In rigorous statistical cost research, it is commonly assumed that a capital good provides a stream of services over some period of time (i.e., service life of the asset). The capital quantity index measures this flow, while the capital price index measures the trend in the price of a unit of capital service. The design of the capital service price index is consistent with the assumption about the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice between some monetary methods is the pattern of decay in the service flow from capex in a given year. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile. Another issue in the choice between monetary methods is whether plant is valued in historic dollars or replacement dollars. Three monetary methods have been used in X factor calibration research:

1. Geometric Decay ("GD"). Under the GD method, the flow of services from investments in a given year declines at a constant rate ("*d*") over time. The quantity of capital at the end of each period

[17] The growth rate of capital cost equals the sum of the growth rates of the capital price and quantity indexes.

t ("XK_t") is related to the quantity at the end of *last* period and the quantity of gross plant *additions* ("XKA_t") by the following "perpetual inventory" equation:

$$XKt = XK_{t-1} \bullet (1-d) + XKA_t \; . \tag{13a}$$

$$= XK_{t-1} \bullet (1-d) + \frac{VKA_t}{WKA_t}. \tag{13b}$$

Here *d* is the (constant) rate of decay in the quantity of older capital. In Relation [13b], the quantity of capital added each year is measured by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*"). In research on the productivity of U.S. energy utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose.

The GD method assumes a replacement (i.e., current dollar) valuation of plant. Replacement valuation differs from the historical (a.k.a. "book") valuation used in North American utility accounting. Cost is computed net of capital gains and the capital service price reflects this.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, OHS in practice applies this constant flow assumption to plant additions for large groups of assets. The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t").

$$XK_t = XK_{t-1} + XKA_t - XKR_t. \tag{14a}$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \tag{14b}$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the assets retired were added.

Plant is once again valued at replacement cost. Cost is computed net of capital gains and the capital service price reflects this.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are different from those used to calculate capital cost under traditional COS

ratemaking.[18] With both approaches, the trend in capital cost is a simulation of the trend in cost incurred for capital services in a competitive rental market. It may be argued that the derivation of an RCI using index logic (*see supra* 10-11) does not require a service price treatment of the capital price.

An alternative COS approach to measuring capital cost has been developed that decomposes capital cost into a price and quantity index using a simplified version of COS accounting. Capital cost is not intended to simulate the cost of capital services in a competitive rental market. Capital price cannot be represented as a capital service price. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review.[19]

Benchmark Year Adjustments

Utilities have various methods for calculating depreciation expenses that they report to regulators. It is, therefore, desirable when calculating capital quantities using a monetary method, to rely on the reporting companies chiefly for the value of gross plant additions but to use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

[18] The OHS assumptions are more markedly different.

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been discussed at some length in PBR proceedings.[20] Based on PEG's experience in proceedings of this nature, we believe that the following considerations are particularly relevant:

1. The goal of productivity research in X factor calibration is to find a just and reasonable means to adjust rates between rate applications.

   Productivity studies have many uses but the best methodology for one application may not be best for another application. One use of productivity research is to measure the trend in a utility's operating efficiency. Another use is to calibrate the X factor in a price-cap or revenue-cap index.

   Rate and revenue cap indexes used in MRPs of utilities, including NGrid's proposal, are intended to adjust utility revenue between general rate cases that employ a cost of service approach to capital cost measurement. In North America, the calculation of capital cost for ratemaking typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of each asset shrinks over time as depreciation reduces net plant value and the return on rate base.

2. OHS is not preferable to GD as the foundation for a monetary approach to capital quantity measurement.

   The OHS specification is sometimes argued to better fit the service flows of individual utility assets. OHS has been used in some productivity studies filed in proceedings to determine X factors.

   Other considerations suggest that the OHS specification is disadvantageous. Here are some notable problems:

- *OHS is More Difficult to Implement Accurately than GD.* A comparison of equations [13b] and [14b] shows that implementation of GD and OHS both require a deflation of gross plant *additions*. This is straightforward since the years of the additions are known exactly. The

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

challenge with OHS is that it also requires the deflation of plant *retirements.* The vintages of reported retirements are generally unknown to persons outside the company. OHS practitioners commonly deflate the value of retirements by the value of the construction cost index for a year in the past that reflects the assumed average service life of the assets.

Examining equation [14b], the quantity of capital in a given year will be smaller when the quantity of retirements is larger. The estimated quantity of retirements will be larger when the average service life of the assets is higher. Thus, TFP growth tends to be more rapid under the OHS approach when the average service life that is used in calculations is higher.

PEG's empirical research suggests that productivity results using OHS are quite sensitive to the average service life assumption. Seemingly reasonable service life estimates can produce negative capital quantities for some utilities. In power distribution productivity research in other proceedings, PEG found results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using GD.[21,22] The sensitivity of OHS results to service life assumptions can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994.

It should also be noted that the mathematical coding for GD is particularly intuitive and easy to implement and review. The OHS specification involves a complicated capital service price that lacks intuition. See, by way of illustration, the OHS capital input price formula stated in Exh. NG-MEM-1, at 58. The derivation of an OHS capital service price is discussed in the Appendix.

- *Prices in Many Used Asset Markets are Inconsistent with an OHS Assumption.* Alternative patterns of physical asset decay involve different patterns of asset value depreciation. Accordingly, trends in used asset prices can shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not

[21] *See, e.g.*, Lowry, M.N. and Hovde, D., *PEG Reply Evidence*, Exhibit 20414-X0468, AUC Proceeding 20414, revised June 22, 2016, pp. 15-18.

[22] *See also*, Exh. M2, Tab 11.1, Sch. OPG-002, Att. A of the OEB's EB-2016-0152 proceeding for PEG's attempt to implement an established form of OHS for hydroelectric power generation.

consistent with the OHS assumption.[23] Instead, depreciation patterns, like that commensurate with GD, appear to be the norm for machinery and are generally the norm for buildings as well.[24]

- *An OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets.* In real-world productivity studies, capital quantity trends are rarely, if ever, calculated for individual assets. Instead, capital quantity trends are calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the aggregate plant additions could be poorly approximated by OHS for several reasons:

1. Assets of the same kind could end up having different service lives. Identical light bulbs installed by homeowners on June 1 in a given year, for instance, will burn out at different times;
2. Different kinds of assets can have markedly different service lives; and
3. Individual assets, in any event, frequently have components with different service lives. The tires in a motor vehicle, for example, typically need replacement several times before the wheels need to be replaced.

Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement

[23] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[24] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 101.

> patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[25] [italics in original]

- *Power Distributor Assets Do Not Exhibit a Constant Flow of Services.* A common sign of decline in the flow of services from an asset is a rise in the expenses to operate and maintain it. Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. Utilities tend to experience rising OM&A expenses and refurbishment capex as many of their assets age.

- *The OHS Approach is Less Widely Used.* The disadvantages of the OHS method help to explain why alternative specifications are favored in productivity and capital quantity research. For example, GD is used to calculate capital quantities in the National Income and Product Accounts of the U.S. and Canada. Statistics Canada also uses GD in its MFP studies for sectors of the economy.[26] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand use hyperbolic decay, not OHS*,* in their sectoral MFP studies.

  GD has also been the capital cost specification most widely used in productivity studies intended for X factor calibration in the North American energy and telecommunications industries. GD is routinely used today in productivity and other statistical cost research by consultants serving Ontario electric utilities. PEG personnel have used the GD approach in most of its more than 30 productivity studies in work for diverse clients that have included Boston Gas.[27] PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used

[25] OECD, *op. cit.*, at 12.

[26] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program," *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14., p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

[27] D.P.U. 96-50.

GD.[28] Laurits R Christensen, major professor in the PhD committee of Dr. Makholm, and his colleague Dr. Mark Meitzen of LRCA used GD in virtually all of their numerous studies of telecommunications utility productivity. LRCA has to our knowledge also used GD in most of their studies over the years of *energy* utility productivity, including ones for the staff of Maine Public Utilities Commission and for Union Gas.[29] Concentric Energy Advisors used GD in their gas utility productivity study for Enbridge Gas Distribution in Ontario.[30]

[28] Lowry, M.N., Deason, J., and Makos, M. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July, pp. B.19-20.

[29] *See, e.g.*, Maine PUC proceeding 2007-00215 and Hemphill, R., and Schoech, P. (1999), "An Evaluation of the Union Gas Limited Performance-Based Regulation Proposal", at 25. Dr. Schoech was listed in response to information request AG-23-3b as a member of the LRCA team for the NGrid project.

[30] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution*, OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

4. Critique of LRCA's Productivity Research and Testimony

4.1. Background

LRCA's study for NGrid has its origins in power distribution productivity research by National Economic Research Associates ("NERA"). An early version of this study was prepared for a Central Maine Power proceeding in the late 1990s.[31] In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare an analogous study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. Since many customer services are no longer provided by distributors in Alberta, NERA removed the cost of these services from its study for the AUC as well as administrative and general ("A&G") expenses.

NERA's study featured an unusually long sample period and advocated an X factor based on results for the full sample period. An unusual feature of the study was a negative MFP trend after 2000. Power distribution studies by PEG have not shown such a trend. Rather than undertake original productivity research, some utility witnesses in this proceeding embraced results of the NERA study for the period after 2000. The AUC rejected their recommendations and instead based its 0.96% base productivity trend on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify. The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study with some modifications rather than undertaking original studies. Each consultancy based their X factor recommendations on results since 2000. LRCA argued that X factor calibration research should be "forward looking". The witness for LRCA, Dr. Mark Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC's 0.30% X factor recommendation was informed by utility studies using OHS but also by a study by PEG that used GD and found that the average TFP trend of U.S. power distributors was 0.43%.

NERA subsequently presented an updated version of its power distribution productivity study in testimony that supported a PBR proposal by two Ontario gas utilities. NERA and OEB's consultant

[31] Maine PUC Case 1999-00666.

recommended a 0% base productivity trend for these utilities, which was ultimately approved by the Board.

PEG was a participant in these proceedings and opposed the NERA/LRCA methodology. We argued that the marked slowdown in productivity growth around 2000 was chiefly due to NERA's use of a volumetric output index. Volumetric output indexes are sensitive to the decline in residential and commercial use per customer, as discussed in Section 3.1 above. The decline in average use growth has been real but is not very relevant to the design of RCIs for power distributors.

PEG has also been critical of NERA/LRCA's capital cost treatment. We have argued that the OHS approach to measuring capital cost has notable disadvantages and that the NERA/LRCA treatment of OHS is flawed. When the OHS treatment is upgraded, power distributor productivity growth is not negative. We argued that NERA obtained a reasonable TFP trend over their lengthy full sample period in their Alberta study because brisk growth in average use in the early years offset productivity declines in later years. In recent years, NERA-style TFP indexes have been declining due to a combination of declining average use and an inappropriate capital cost specification.

In its study for Eversource, LRCA's methodology remained quite similar to that of NERA.[32] One notable change was to use the number of customers as the output index. LRCA did not include the costs of customer services or A&G tasks even though these were costs incurred by Eversource. In addition to a substantially negative productivity differential, LRCA also computed a substantially negative input price differential. Although the Department embraced LRCA's research, including its use of OHS, the Department adopted a lower X factor than LRCA recommended.[33]

Following the Eversource decision, the X factor issue was revisited by the Régie de l'énergie in a recent Québec proceeding to design an RCI for power distribution services of Hydro-Québec.[34] PEG was a witness in this proceeding for industrial intervenors. With knowledge of both the Department's decision in D.P.U. 17-05 and PEG's critique of the NERA/LRCA methodology, the Régie acknowledged a 0.3% distribution industry productivity trend.

[32] *Compare* Exh. NG-MEM-1 *with* D.P.U. 17-05, Exh. ES-PBRM-1.

[33] D.P.U. 17-05, at 392.

[34] Québec Régie de l'énergie, R-4011-2017.

4.2. LRCA's Study for NGrid

For this proceeding, LRCA calculated the input price and productivity trends of a sample of U.S. utilities in the provision of power distributor services over the fourteen-year period 2003-2016.[35] The number of customers was used to measure output growth.

Unlike the Eversource study, expenses for A&G tasks and certain customer services were added to LRCA's NGrid study. Dr. Meitzen stated that A&G expenses were allocated on a "non-economic conceptual basis." Exh. NG-MEM-1, at 32. He stated further that his "plant-apportioned" results that allocate A&G "provides a balance between the economic measure of [TFP] and non-economic considerations of a traditional approach to the ratemaking process." Exh. NG-MEM-1, at 48.

Dr. Meitzen stressed that the X factor should be "forward looking", stating that:

> Although [the X factor] is typically determined by a productivity study that is based on historical information, [the X factor] is forward looking as it is based on those differentials that are expected to prevail over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.
>
> Exh. NG-MEM-1, at 29.

Dr. Meitzen further stated that:

> The 15 year period strikes a balance between using the most recent, relevant information for determining forward-looking changes in productivity and using a period long enough to account for short term variation in results.
>
> Exh. NG-MEM-1, at 33.

For the full national sample and "plant apportioned" cost, LRCA reported a -0.13% TFP trend and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials. The sum of the resultant -0.95% productivity differential and -0.77% input price differential was a base X factor of **-1.72%**.[36] LRCA also produced results for a Northeast sample of utilities in the New England and mid-Atlantic states. LRCA reported a -0.69% Northeast MFP trend and a brisk 3.48% input price trend. The sum of the resultant -1.51% productivity differential and -0.75% input

[35] Exhibit NG-MEM-1 at 35.

[36] Exhibit NG-MEM-1, Figure 9, at 44.

price differential was a base X factor of **-2.27%**. LRCA recommends that the base X factor be based on the national plant-apportioned results.

4.3. Major Concerns

LRCA's methodology for measuring power distribution productivity and its discussion of RCI design are controversial. To facilitate the Department's review of the numerous and sometimes complicated issues that arise in productivity studies, below are PEG's most important concerns regarding LRCA's methodology.

<u>Capital Specification</u>

PEG has concerns about the OHS approach that LRCA used to measure capital cost. PEG discussed several general disadvantages of the OHS approach in Section 3.2 above. Here, we argue that LRCA's particular approach to executing OHS is flawed. Since LRCA does not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the choice of the average service life used in the conversion of the total value of distribution plant retirements each year to a quantity.

LRCA assumes a 33-year average service life.[37] The basis for this specification is presented in response to information request AG-15-4 and AG-23-4. They sought to estimate average service life by calculating a weighted average of the service lives for various distribution asset classes which utilities report periodically on FERC Form 1. The weights are the shares of each asset class in plant value.

The requisite data were readily available for this calculation only from 1994 to 2016. LRCA reports that the median average service life thus calculated rose over this period from 37.29 years in 1994 to 46.35 years in 2016.

LRCA claims that, since capital data for the 1964 to 2016 period are used in its capital quantity calculations, the average service life should be set at the value for the midpoint of this interval, which is 1990. The value of this is unavailable for 1990 but LRCA maintains that an appropriate value is the 33 years that NERA also used.

PEG has several reservations about LRCA's average service life calculations.

[37] Exhibit NG-MEM-1, pages 56 and 59.

- The average service life for 1990 is unknown. Different estimates for its value can be reasonably entertained.

  LRCA noted that there existed an upward trend in service lives to 2016 which we calculated as 0.87% per year. Using the LRCA 1994 mean value of 38.96 years and the 0.87% trend results in a value of 37.635 years in 1990. A similar calculation using the median as opposed to mean values results in a 1990 estimate of 35.84 years. A few years difference in the estimated service life may not seem material, but we have found that the OHS method is highly sensitive to the assumed service life.

- LRCA's analysis relies on utility *estimates* of average service lives which were reported to the FERC. These estimates were not always freshly calculated and rise substantially over time. It is therefore likely that they were *downward biased* as estimates of the true service lives of assets at the time that they were reported.

- The average service life at the *midpoint* of the 1972-2016 period is unlikely to be representative of retirements that occurred between 2002 and 2016.

- Average service lives going forward are clearly much higher than they were in 1990. Freezing the average service life at its estimated 1990 value seems inconsistent with LRCA's goal of calculating a forward-looking X factor.

PEG notes that the controversy over average service life when OHS is used to calculate capital cost is unfortunate and a good reason to consider results using different capital cost methods. Since the Department is nonetheless interested in results using OHS, we believe that the evidence points to an OHS value of 36 years.

The benchmark year adjustment that NERA used is another problem. We noted in Section 3 above that the computation of a capital quantity index starts with a benchmark year adjustment. PEG believes that LRCA's calculations of capital quantity indexes in its benchmark year are incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with *gross* plant value. Yet LRCA deflated *net* plant values by an average of past values of a construction cost index. Consequently, PEG believes that the initial quantities of capital for each utility in LRCA's sample are understated. LRCA's method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this understated initial capital stock can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[38] A related concern is that LRCA, like NERA, did not assume a consistent 33-year average service life in making its benchmark year calculation.

Input Price Differential Calculations

NERA's input price differential calculations are also a cause for concern. As discussed in Section 3.2 above, input price differentials using implicit service price indexes are inherently awkward in X factor calibrations because assets are valued in current dollars and capital gains are considered. The 2003-2016 sample period used by LRCA was especially problematic since power distribution construction costs rose rapidly, due in part to a run-up in copper prices that was never fully reversed. This runup is illustrated in Figure 1 below, which compares GDP-PI inflation to the inflation in the producer price index for copper wire and Handy Whitman electric power distribution construction cost index.

LRCA has compounded this problem in two ways:

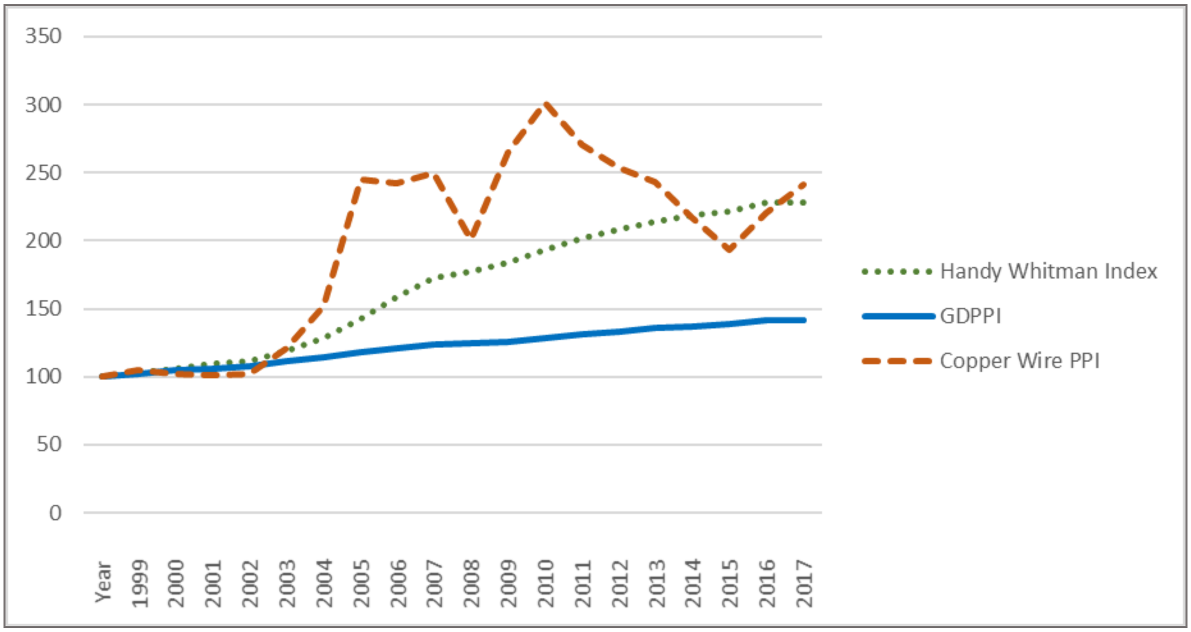
1. The sample period LRCA used is, in our opinion, too short to accurately calculate a long-term input price differential. In its recent Ontario testimony, NERA calculated an input price differential using power distribution data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[39]
2. LRCA froze the expected real rate of return in its input price index, stating that it assumed that "investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time."[40] However, LRCA allowed the construction cost index to accelerate briskly. In so doing, LRCA permitted the input price index to grow rapidly, thereby imparted a substantial negative bias to its input price differential calculations.

[38] Brattle Undertaking #4 as filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0564 and Transcript Volume 8, pp. 2808-2809 from Alberta Utilities Commission Proceeding 20414.

[39] OEB proceeding EB-2017-0307, Exhibit B, Tab 2, filed November 23, 2017, p. 32.

[40] Exh. NG-MEM-1, at 59.

Figure 1
Trends in Power Distribution Construction Costs



Sampled Companies

LRCA excluded numerous companies from its sample even though the data were available, apparently because these companies were not part of the original NERA sample. Substantially larger samples are feasible.[41]

Revenue Cap Index Design

PEG's explanation in Section 3.1 of the principles for RCI design differs from LRCA's. Particularly, we show that the scale index used to calculate TFP growth need not be the number of customers served. An elasticity-weighted scale index can be used to measure output in such research. This implies that an RCI that lacks an explicit scale escalator does not necessarily offer customer growth as an "implicit stretch factor". Trends in other scale variables can be considered. Econometric research on electric distribution cost which PEG just presented in Toronto testimony found that the number of

[41] *See, e.g.*, Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, for Lawrence Berkeley National Laboratory, July 2017, p. B.13 where PEG undertook a power distributor productivity study with 86 power distributors.

customers served has an estimated cost elasticity of 0.601 but ratcheted peak demand has an estimated elasticity of 0.351.[42] The share of peak demand in the sum of the two elasticities is a sizable 37%.[43] We acknowledge, however, that the number of customers has been used in productivity studies, including studies by PEG, to calibrate the X factors of RCIs for gas and electric power distributors. These studies were sometimes done with the expectation that a revenue per customer cap would be approved.

Other Concerns

There are a number of smaller problems with LRCA's U.S. power distribution research. Taken together they have little effect on LRCA's research results but nonetheless merit mention.

- LRCA failed to correct for some mergers;
- Pension and benefit expenses are included in the study even though NGrid proposes to track the cost of these expenses;
- Pension and benefit expenses were inappropriately treated as material and service expenses. This led to more volatile and inaccurate TFP results;
- Even though pension and benefit expenses are included in the study, LRCA uses an employment cost index for salaries and wages to deflate labor cost rather than an ECI for total compensation.

Alternative Results

To illustrate some of the problems with LRCA's capital cost treatment, PEG has developed an alternative calibration exercise using LRCA's data. First, the benchmark year capital quantity calculation was revised to deflate *gross* plant value. Next, the average service life was raised from 33 to 36 years. In addition, the input price index was changed to unfreeze the expected real rate of return.

Results of this exercise are presented in Tables 1a, 1b, and 1c below. TFP growth for the full national sample averaged 0.30%. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor from this research is therefore **0.04%**. The analogous result using Northeast US data is **-0.64%**. Thus, replacing the flawed NERA/LRCA approach to the OHS capital cost calculations with a more defensible treatment produces a substantially higher X factor that is less favorable to NGrid.

[42] Lowry, M.N., *IRM Design for Toronto Hydro-Electric System*, OEB, EB-2018-0165, Exhibit M1, March 20, 2019.

[43] The ratcheted peak demand of a utility is the highest value that it has yet attained.

Table 1a

PEG Modifications to LRCA Analysis – Distribution Industry

Period	Output Quantity	Input Quantity	Revenue Per Customer MFP	Input Price
2002	-	-	-	-
2003	1.28%	3.33%	-2.05%	-2.07%
2004	1.14%	-2.49%	3.63%	2.18%
2005	1.42%	1.20%	0.21%	2.01%
2006	1.04%	6.95%	-5.90%	7.10%
2007	1.07%	-4.95%	6.02%	5.90%
2008	0.64%	-0.65%	1.28%	6.50%
2009	0.08%	0.41%	-0.33%	2.88%
2010	0.38%	2.28%	-1.90%	-0.68%
2011	0.36%	1.00%	-0.64%	0.78%
2012	0.52%	1.31%	-0.78%	-3.44%
2013	0.80%	-2.86%	3.66%	6.61%
2014	0.60%	-0.27%	0.87%	2.21%
2015	0.77%	-0.31%	1.08%	0.21%
2016	0.89%	1.86%	-0.97%	0.21%
Average	**0.78%**	**0.49%**	**0.30%**	**2.17%**
Original LRCA Results				
Average	**0.78%**	**0.91%**	**-0.13%**	**3.50%**
Difference	0.00%	-0.42%	0.43%	-1.33%

Table 1b

PEG Modifications to LRCA Analysis – U.S. Economy

Year	GDPPI	MFP	Input Price
	[A]	[B]	[A] + [B]
2002	-	-	-
2003	1.87%	2.29%	4.15%
2004	2.64%	2.61%	5.25%
2005	3.05%	1.53%	4.58%
2006	3.01%	0.35%	3.36%
2007	2.66%	0.39%	3.04%
2008	1.89%	-1.19%	0.70%
2009	0.78%	-0.26%	0.52%
2010	1.16%	3.25%	4.42%
2011	2.06%	0.07%	2.13%
2012	1.91%	0.69%	2.60%
2013	1.76%	0.41%	2.16%
2014	1.86%	0.87%	2.73%
2015	1.03%	0.93%	1.96%
2016	1.08%	-0.46%	0.62%
Average	**1.91%**	**0.82%**	**2.73%**
Original LRCA Results			
Average	**1.91%**	**0.82%**	**2.73%**
Difference	0.00%	0.00%	0.00%

Table 1c

X Factor Calculations Using an Alternative OHS Capital Cost Specification

	MFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
	[A]	[B]	[C=A-B]	[D]	[E]	[F=D-E]	[G=C+F]
2002	-	-	-	-	-	-	-
2003	-2.05%	2.29%	-4.34%	4.15%	-2.07%	6.22%	1.89%
2004	3.63%	2.61%	1.02%	5.25%	2.18%	3.07%	4.09%
2005	0.21%	1.53%	-1.32%	4.58%	2.01%	2.57%	1.25%
2006	-5.90%	0.35%	-6.25%	3.36%	7.10%	-3.74%	-9.99%
2007	6.02%	0.39%	5.63%	3.04%	5.90%	-2.86%	2.78%
2008	1.28%	-1.19%	2.47%	0.70%	6.50%	-5.80%	-3.33%
2009	-0.33%	-0.26%	-0.07%	0.52%	2.88%	-2.36%	-2.43%
2010	-1.90%	3.25%	-5.15%	4.42%	-0.68%	5.10%	-0.06%
2011	-0.64%	0.07%	-0.71%	2.13%	0.78%	1.35%	0.64%
2012	-0.78%	0.69%	-1.47%	2.60%	-3.44%	6.04%	4.57%
2013	3.66%	0.41%	3.25%	2.16%	6.61%	-4.45%	-1.19%
2014	0.87%	0.87%	0.00%	2.73%	2.21%	0.52%	0.52%
2015	1.08%	0.93%	0.15%	1.96%	0.21%	1.75%	1.90%
2016	-0.97%	-0.46%	-0.51%	0.62%	0.21%	0.41%	-0.10%
Average	**0.30%**	**0.82%**	**-0.52%**	**2.73%**	**2.17%**	**0.56%**	**0.04%**
Original LRCA Results							
Average	**-0.13%**	**0.82%**	**-0.95%**	**2.73%**	**3.50%**	**-0.77%**	**-1.72%**
Difference	0.43%	0.00%	0.43%	0.00%	-1.33%	1.33%	1.76%

5. Productivity Research by PEG

5.1. Data

The primary source of the cost and quantity data for PEG's independent research on input price and productivity trends of U.S. power distributors is FERC Form 1. Selected FERC Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[44] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. The FERC Form 1 data used in PEG's study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the FERC Form 1 in 1964 (the benchmark year for our study, described further below) and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the PEG study, the data also were required to be of good quality and plausible. Data from 80 utilities met PEG's standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table 2 below lists the companies from which PEG's data were drawn. It can be seen that most broad regions of the United States are well represented.[45]

[44] This publication series had several titles over the years. A recent title is Financial Statistics of Major U.S. Investor-Owned Electric Utilities.

[45] Unfortunately, the requisite customer data are not available for most Texas distributors.

Table 2
Sample of Utilities Used in Productivity Model Research

Alabama Power	Madison Gas and Electric
ALLETE (Minnesota Power)	MDU Resources Group
Appalachian Power	Metropolitan Edison*
Arizona Public Service	Mississippi Power
Atlantic City Electric*	Monongahela Power
Avista	Nevada Power
Baltimore Gas and Electric	New York State Electric & Gas*
Black Hills Power	Niagara Mohawk Power*
Central Hudson Gas & Electric*	Northern Indiana Public Service
Central Maine Power*	Northern States Power - MN
Cleco Power	Ohio Edison
Cleveland Electric Illuminating	Oklahoma Gas and Electric
Commonwealth Edison	Orange and Rockland Utilities*
Connecticut Light and Power*	Pacific Gas and Electric
Consolidated Edison Company of New York*	Potomac Electric Power*
Delmarva Power & Light	Pennsylvania Electric*
DTE Electric	Pennsylvania Power*
Duke Energy Carolinas	Portland General Electric
Duke Energy Florida	PPL Electric Utilities*
Duke Energy Indiana	Public Service Company of Colorado
Duke Energy Kentucky	Public Service Company of New Hampshire*
Duke Energy Ohio	Public Service Company of Oklahoma
Duke Energy Progress	Public Service Electric and Gas*
Duquesne Light*	Puget Sound Energy
El Paso Electric	San Diego Gas & Electric
Empire District Electric	South Carolina Electric & Gas
Entergy Arkansas	Southern California Edison
Entergy Mississippi	Southern Indiana Gas and Electric
Entergy New Orleans	Southwestern Public Service
Florida Power & Light	Tampa Electric
Gulf Power	Toledo Edison
Idaho Power	Tucson Electric Power
Indiana Michigan Power	Union Electric
Indianapolis Power & Light	United Illuminating*
Jersey Central Power & Light*	Virginia Electric and Power
Kansas City Power & Light	West Penn Power*
Kansas Gas and Electric	Western Massachusetts Electric*
Kentucky Power	Wisconsin Electric Power
Kentucky Utilities	Wisconsin Power and Light
Louisville Gas and Electric	Wisconsin Public Service

Total of 80 Companies

*** Indicates a member of the Northeast Sample**

5.2. Defining Costs

The major tasks in power distribution are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered. Most power is delivered to customers at the voltage at which it is consumed. This requires distributors to step down the voltage of power from the voltage at which they receive it from the transmission sector.[46] Distributors use transformers near the point of delivery to reduce voltage to the level at which it is consumed. Some also own and operate substations that receive power at subtransmission or transmission voltage.

Distributors also typically provide various customer services. In the United States, these typically include metering, meter reading, customer account, and customer service and information ("CS&I") services. Expenses reported on FERC Form 1 for CS&I services include those for utility DSM programs. These expenses will be subject to tracker treatment in National Grid's proposed plan, vary widely between utilities, and are not itemized for easy removal. We accordingly excluded all CS&I expenses from the costs of the utilities in our study.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. NGrid has proposed to track these expenses in its PBR plan. Consequently, unlike LRCA, PEG has excluded these expenses in this study.

The O&M expenses that PEG used in the study for U.S. utilities included those for power distribution, customer accounts, metering, and meter reading. We also included a sensible share of A&G expenses.[47] PEG excluded all reported O&M expenses incurred by sampled U.S. utilities for generation, power procurement, transmission, customer service and information, franchise fees, and gas services. The capital costs were those for distribution plant.

The total cost of power distributor services considered in the PEG study was the sum of capital costs and applicable O&M expenses. In our input price and productivity research for the AGO we employed a monetary approach to capital cost, price, and quantity measurement which featured GD.

[46] Some large industrial customers take delivery of power directly from the transmission system.

[47] This procedure is theoretically arbitrary but has little impact on results.

Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[48] Further details of PEG's capital cost calculations are provided in Appendix Section A.1.

5.3. Input Price Indexes

Operation & Maintenance

The labor prices for U.S. utilities were escalated by regionalized Bureau of Labor Statistics ("BLS") Employment Cost Indexes for salaries and wages. Material and service ("M&S") prices were escalated by the U.S. GDP-PI.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research. PEG calculated weighted averages of rates of return for debt and equity.[49] PEG calculated for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[50] PEG used construction cost indexes from Whitman, Requardt and Associates to deflate the value of plant additions of the sampled distributors.

Summary Input Price Index

Summary input price indexes were constructed by PEG which were weighted averages of price subindexes for various inputs. Calculation of these indexes used company-specific, time-varying cost share weights for the U.S. utilities. The cost shares were calculated from FERC Form 1 O&M expense data.

[48] Capital gains are included due to the geometric decay capital cost treatment that we employ, as noted in Section 3.2 values capital at replacement cost.

[49] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

[50] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

5.4. Scope of Research

PEG calculated indexes of growth in the O&M, capital, and total factor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

5.5. Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. PEG used the growth in the total number of retail customers served as the scale metric.

In calculating input quantity trends, we broke down the applicable cost into three categories: (1) distribution plant; (2) labor; (3) M&S inputs. The cost of labor was defined for this purpose as O&M salaries and wages. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of each total factor input quantity index was a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

5.6. Sample Period

The full sample period for which productivity results were calculated was 1997-2017.[51] The year 2017 is the latest for which the required data are currently available.

5.7. Index Results

Table 3 below summarizes our productivity research for the U.S. sample. Over the full 1997-2017 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors using GD was about +0.33%. The productivity differential was -0.65%.

Table 4 below presents PEG's input price results. The input price growth of the industry averaged 2.89% over the full sample period. The input price growth of the economy averaged 2.83%. The input price differential was -0.06%, close to zero. The sum of the input price and productivity differentials was **-0.71%.** This is the indicated base X factor from this research. The analogous base X factor using Northeast data was **-0.74%.**

[51] In other words, 1997 was the earliest year for growth rate calculations.

Table 3

Calculating the Productivity Differential – U.S.[1]

	Productivity Indexes								Productivity Differential
	U.S. Power Distributors						U.S. Private Business MFP Index[2]		
	Output Quantity		Input Quantity		Productivity				
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate [A]	Index	Growth Rate [B]	[A] - [B]
1996	100.00		100.00		100.00		100.00		
1997	101.39	1.38%	99.74	-0.26%	101.66	1.65%	101.13	1.12%	0.53%
1998	102.99	1.56%	102.08	2.33%	100.89	-0.76%	102.64	1.48%	-2.25%
1999	104.33	1.29%	104.06	1.92%	100.25	-0.63%	104.61	1.90%	-2.53%
2000	105.84	1.44%	104.61	0.52%	101.18	0.92%	106.11	1.43%	-0.51%
2001	107.94	1.97%	104.25	-0.34%	103.54	2.31%	106.59	0.45%	1.87%
2002	109.42	1.36%	104.94	0.66%	104.27	0.70%	108.76	2.02%	-1.32%
2003	110.33	0.83%	107.53	2.44%	102.60	-1.62%	111.27	2.29%	-3.90%
2004	111.66	1.20%	106.04	-1.40%	105.30	2.60%	114.21	2.61%	-0.01%
2005	113.18	1.36%	106.77	0.68%	106.01	0.67%	115.97	1.53%	-0.85%
2006	113.71	0.47%	107.64	0.81%	105.64	-0.34%	116.38	0.35%	-0.70%
2007	114.91	1.05%	110.19	2.35%	104.28	-1.30%	116.83	0.39%	-1.68%
2008	115.62	0.61%	109.74	-0.41%	105.35	1.02%	115.45	-1.19%	2.21%
2009	115.88	0.23%	108.38	-1.24%	106.92	1.47%	115.16	-0.26%	1.73%
2010	116.45	0.50%	109.48	1.01%	106.37	-0.52%	118.96	3.25%	-3.77%
2011	116.76	0.27%	109.85	0.33%	106.30	-0.07%	119.05	0.07%	-0.13%
2012	117.28	0.44%	109.92	0.07%	106.69	0.37%	119.87	0.69%	-0.32%
2013	117.92	0.55%	109.26	-0.61%	107.93	1.15%	120.36	0.41%	0.75%
2014	118.60	0.58%	110.20	0.86%	107.63	-0.28%	121.41	0.87%	-1.15%
2015	119.50	0.75%	110.30	0.09%	108.34	0.66%	122.55	0.93%	-0.27%
2016	120.61	0.92%	111.78	1.33%	107.90	-0.40%	121.98	-0.46%	0.06%
2017	121.57	0.79%	113.37	1.41%	107.23	-0.62%	122.90	0.76%	-1.38%
Average Annual Growth Rate									
1997-2017		**0.93%**		**0.60%**		**0.33%**		**0.98%**	**-0.65%**

[1]All growth rates calculated logarithmically.
[2]Source: U.S. Bureau of Labor Statistics

Table 4
Calculating the Input Price Differential – U.S.[1]

	Input Price Indexes								Input Price Differential
	United States						U.S. Power Distributor Input Prices		
	GDP-PI[2]		MFP[3]		Implied IPI				
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Growth Rate
		[A]		[B]		[C=A+B]		[D]	[E=C-D]
1996	100.00		100.000		100.00		100.00		
1997	101.73	1.72%	101.13	1.12%	102.88	2.84%	105.07	4.94%	-2.11%
1998	102.85	1.10%	102.64	1.48%	105.57	2.58%	108.59	3.29%	-0.71%
1999	104.33	1.42%	104.61	1.90%	109.14	3.32%	111.19	2.37%	0.95%
2000	106.68	2.23%	106.11	1.43%	113.20	3.66%	110.71	-0.44%	4.09%
2001	109.08	2.22%	106.59	0.45%	116.26	2.67%	111.30	0.53%	2.14%
2002	110.74	1.51%	108.76	2.02%	120.44	3.53%	108.76	-2.31%	5.84%
2003	112.83	1.87%	111.27	2.29%	125.55	4.15%	110.53	1.62%	2.54%
2004	115.85	2.64%	114.21	2.61%	132.32	5.25%	106.35	-3.85%	9.11%
2005	119.44	3.05%	115.97	1.53%	138.52	4.58%	99.75	-6.41%	10.99%
2006	123.09	3.01%	116.38	0.35%	143.25	3.36%	82.78	-18.65%	22.01%
2007	126.40	2.66%	116.83	0.39%	147.68	3.04%	73.68	-11.63%	14.67%
2008	128.81	1.89%	115.45	-1.19%	148.72	0.70%	71.58	-2.89%	3.60%
2009	129.82	0.78%	115.16	-0.26%	149.49	0.52%	101.57	34.99%	-34.47%
2010	131.34	1.16%	118.96	3.25%	156.24	4.42%	130.21	24.84%	-20.42%
2011	134.07	2.06%	119.05	0.07%	159.61	2.13%	151.25	14.98%	-12.85%
2012	136.65	1.91%	119.87	0.69%	163.81	2.60%	149.59	-1.10%	3.70%
2013	139.08	1.76%	120.36	0.41%	167.39	2.16%	152.80	2.12%	0.04%
2014	141.69	1.86%	121.41	0.87%	172.02	2.73%	161.88	5.77%	-3.04%
2015	143.15	1.03%	122.55	0.93%	175.43	1.96%	170.93	5.44%	-3.48%
2016	144.71	1.08%	121.98	-0.46%	176.52	0.62%	182.78	6.70%	-6.08%
2017	147.49	1.90%	122.90	0.76%	181.27	2.66%	183.50	0.39%	2.26%
Average Annual Growth Rate									
1997-2017		**1.85%**		**0.98%**		**2.83%**		**2.89%**	**-0.06%**

[1]All growth rates calculated logarithmically

[2]Gross Domestic Product Price Index calculated by the BEA.

[3]Multifactor productivity for the U.S. private business sector calculated by the BLS.

5.8. Kahn Method Research

A base X factor was also calculated for NGrid using a simpler "Kahn Method" exercise. This method was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. It has been used by the FERC to set the X factors in PBR plans for interstate oil pipelines. In an application to this proceeding, PEG would calculate trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting and then solve for the value of X which would have caused the trend in distributor cost to equal the trend in a generic RCI. The base X factor resulting from such a calculation reflects the input price and productivity differentials of utilities.

Calculating X Using the Kahn Method

PEG postulated a hypothetical generic revenue cap index like that in Relation [8a] with the following form:

$$\textit{growth Allowed Base Revenue}^{\textit{Utility}} = \textit{growth GDPPI} - X + \textit{growth Customers}. \qquad [15]$$

We then calculated the trend in the cost of base rate inputs for each utility in the sample. In these calculations, capital cost was defined as the sum of depreciation and amortization expenses and return on rate base. We excluded costs that were unlikely to be addressed by trackers and riders in NGrid's regulatory system. We calculated the value of X that would cause the trends in the costs of the sampled power distributors to equal the trends in the hypothetical RCIs with formulas like Relation [8] on average over the sample period. The full sample period considered by PEG was the twenty-one-year period, 1997-2017. PEG also considered results for shorter and more recent periods.

Results of this exercise can be seen in Table 5 below. For all sample periods considered, the average annual growth in cost was more rapid than the average annual growth in the GDP-PI. The average annual growth in the number of customers served was not large enough to close this gap. Thus, the X factor must be negative if the hypothetical RCIs are to track historical distributor costs on average. The Kahn X factor was **-0.41%** for the full 1997-2017 sample period. The analogous result for the Northeast sample was **-0.45%.**

Table 5

U.S. Power Distributor Kahn X Factor Calculations[1]

Year	GDP-PI[1]	Customers	Total Cost	Kahn X
	[A]	[B]	[C]	[D=A+B-C]
1997	1.72%	1.38%	2.66%	0.45%
1998	1.10%	1.56%	5.20%	-2.54%
1999	1.43%	1.29%	3.90%	-1.19%
2000	2.23%	1.44%	4.27%	-0.60%
2001	2.22%	1.97%	3.26%	0.93%
2002	1.52%	1.36%	0.17%	2.70%
2003	1.87%	0.83%	3.45%	-0.76%
2004	2.64%	1.20%	0.92%	2.92%
2005	3.06%	1.36%	3.09%	1.32%
2006	3.00%	0.47%	2.84%	0.63%
2007	2.66%	1.05%	5.41%	-1.70%
2008	1.89%	0.61%	3.50%	-1.00%
2009	0.78%	0.23%	2.03%	-1.02%
2010	1.16%	0.50%	3.74%	-2.08%
2011	2.06%	0.27%	3.12%	-0.80%
2012	1.91%	0.44%	2.45%	-0.11%
2013	1.76%	0.55%	1.89%	0.41%
2014	1.87%	0.58%	3.98%	-1.53%
2015	1.03%	0.76%	3.84%	-2.05%
2016	1.08%	0.92%	3.02%	-1.02%
2017	1.90%	0.79%	4.24%	-1.55%
Average Annual Growth Rates				
1997-2017	1.85%	0.93%	3.19%	**-0.41%**
2002-2017	1.89%	0.74%	2.98%	**-0.35%**
2007-2017	1.64%	0.61%	3.38%	**-1.13%**

Note: All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 80 power distributors.

[1]Gross Domestic Product Price Index calculated by the BEA.

6. X Factor Recommendations

6.1. Stretch Factor

The Company proposes a consumer dividend of 0.40% contingent on GDP-PI growth exceeding 2%. The 0.4% recommendation is based on a statistical benchmarking study by Dr. Lawrence R. Kaufmann, President of Kaufmann Consulting. Dr. Kaufmann has done work for PEG as a Senior Advisor, but he is not an employee of PEG, and he worked separately for NGrid in this proceeding. He reported in his testimony that NGrid's productivity level was about 27% below that of NSTAR Electric's over the 2014-16 sample period.

PEG was not asked by the AGO to consider Dr. Kaufmann's study. Accordingly, we take 0.4% as a given in what follows. We note, however, that it is controversial to make a stretch factor contingent on the inflation rate. Inflation has been sluggish in recent years and this may continue. The potential for productivity growth does not vary with inflation and this provision is rare in approved PBR plans. We accordingly do not believe that there should be a stretch factor contingency.

6.2. X Factor

PEG's review of the assembled evidence on industry productivity trends has the following highlights.

- Using our upgraded OHS results and LRCA's national data, the productivity differential of -0.52% and the inflation differential of 0.56% sum to an indicated base X factor of **0.04%.** The indicated base X factor using Northeast data was -0.64%.
- Using our GD method and national data, the productivity differential of -0.65% and the inflation differential of -0.06% sum to base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**
- The indicated base X factor using the Kahn method and national data is **-0.41%.** The analogous result using Northeast data is **-0.45%.**
- Other plan provisions also merit consideration in the choice of an X factor. The stretch factor would be effective only when inflation exceeded 2%. A tracker treatment is proposed for certain grid modernization and electric vehicle costs. Costs of an upgraded vegetation management program would also be tracked.
- The RCI has no scale escalator, but this does not produce an implicit stretch factor equal to expected customer growth. Growth in other scale variables also matters. We have shown that the trend in peak demand matters, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The total X factor would then be -0.20%.

Appendix

Details of the PEG Productivity Research

This Appendix contains more technical details of PEG's productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our method for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary input quantity index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

Each summary input quantity index used in the study was of chain-weighted Törnqvist form. This means that its annual growth rate was determined by the following general formula:

$$\ln\left(Inputs_{t} / Inputs_{t-1} \right) = \sum_{j} \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} / X_{j,t-1} \right). \qquad [A1]$$

Here, in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It is evident that growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

The summary input price indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula.

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \qquad [A3]$$

Here, in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of each utility. As discussed in Section 3.2 above, under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$$CK = WK \cdot XK.$$

GD was assumed. PEG took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity index in the benchmark year were based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year. The construction cost indexes (WKA_t) were the applicable regional Handy-Whitman Index of Cost Trends of Power Distribution Construction.[52]

The following formula was used to compute values of the capital quantity index in subsequent years:

$$XK_t = (1-d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \quad \text{[A4]}$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \quad \text{[A5]}$$

The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was time-variant but smoothed to reduce capital cost volatility.

[52] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, Petition for a General Increase in Electric Rates	D.P.U. 18-150

AFFIDAVIT OF MARK NEWTON LOWRY

Mark Newton Lowry does hereby depose and say as follows:

I, Mark Newton Lowry, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 22nd day of March 2019.

Mark Newton Lowry