L1.SEC.1

1. [Page 23] Does Dr. Lowry have any information on why US power productivity was positive prior to 2000, and negative thereafter? Is there a similar trend in gas distribution, and if so, are the causes similar? If there is not a similar trend, does Dr. Lowry have any information as to why that is the case?

Response to SEC-1: The following response was provided by PEG.

The answer to this question depends on the kind of productivity being measured. The productivity of utilities is sometimes measured using revenue-weighted indexes of trends in their billing determinants. This addresses a comprehensive notion of productivity that encompasses marketing as well as cost performance.

Dr. Lowry explains in Section 3.2 of his report in this proceeding that the trend in this kind of productivity index depends in part on an output differential --- the difference between the impact of output growth on revenue and cost. Although Ontario power distributors are transitioning to fixed/variable rate designs at the OEB's directive, these designs have rarely been allowed for investor-owned US electric utilities because of their adverse effects on conservation and the bills of small-volume customers. The revenue of these utilities is quite sensitive to trends in residential and commercial ("R&C") delivery volumes even though econometric research and other evidence suggests that distributor cost is driven more by growth in customers, line length, and peak demand. The trend in the output differential of these utilities is sometimes approximated by the trend in their R&C deliveries per customer (aka "average use").

Since 2000, growth in the R&C average use of US power distributors has been slowed by conservation programs, sluggish income growth, and tighter appliance efficiency standards and building codes. Dr. Lowry showed in Table 2 of his report that R&C volumes/customer averaged 1.5% annual growth before 2000 but have averaged a 0.3% annual decline since then. Since NERA uses entirely volumetric output indexes, this is the chief source of the decline in their TFP indexes after 2000. However, this slowdown is irrelevant to the choice of an X factor for the Amalco since the Applicants propose separate average use/average consumption adjustments in their IRM. The *negative* productivity growth that NERA reports since 2000 is due, additionally, to errors in NERA's capital cost specification, as Dr. Lowry demonstrates in his report.

Dr. Lowry discusses in Section 3.2 of his report an alternative approach to measuring output that weights output variables on the basis of their relative cost impact as measured by their cost elasticities. Productivity indexes constructed from elasticity-weighted output indexes are effectively cost efficiency indexes. PEG used output indexes of this kind to measure the TFP growth of Ontario power distributors in the 4th generation IRM proceeding.[1]

Since 2000, growth in the cost efficiency of US power distributors may have been slowed somewhat by

[1] The elasticity weights on these indexes are not necessarily appropriate for a US productivity study and are, in any event, now in need of updating.

slower growth in peak load. Opportunities for distributors to save on costs of system capacity when peak demand growth slows are limited in the short run. For example, a distributor has much less ability to reduce *existing* capacity than, say, a "bricks and mortar" retail chain, which can rent less space. Additionally, utilities may not have exploited all opportunities to economize on capital *expenditures* ("capex") that slower demand growth has made possible.

Unfortunately, good data on line length and the peak demand of investor-owned US power distributors are not readily available in the United States. In recent econometric research on the total cost of US power distributors, PEG found the parameter estimate for the available (but flawed) peak load variable to be statistically insignificant even when a sensible adjustment was made to increase its accuracy. The number of customers served is, in any event, an important cost driver and highly correlated with expected peak demand. Cost efficiency indexes are therefore typically calculated using the number of customers as the output variable.

Table SEC-1a shows the trend in the TFP of US power distributors using NERA's data and one hoss shay assumption but several methodological upgrades such as the number of customers as the output variable and a more appropriate benchmark year adjustment and average service life for the capital quantity index. The table also shows the trend in indexes of power distributor productivity which PEG recently calculated for a Lawrence Berkeley National Laboratory study.[2] PEG's research for Berkeley Lab featured a geometric decay capital cost specification, a larger group of utilities than that used by NERA, and a 1980-2014 sample period.

Inspection of the table reveals that TFP using the upgraded NERA indexes averaged 0.85% annual growth from 1980 to 2000 and 0.69% from 2001 to 2014. Thus, there was a modest 16-basis point average slowdown in the cost efficiency indexes. This is much less than the slowdown in NERA's TFP indexes. PEG's TFP indexes meanwhile averaged 0.60% growth from 1980 to 2000 and 0.23% growth from 2001 to 2014. Thus, TFP growth declined by 37 basis points. The TFP trend has not been negative since 2000 using either approach.

Here are some reasons for the modest slowdown in the growth of these cost efficiency indexes of US power distributors since 2000.

- Many distributors have deployed advanced metering infrastructure ("AMI") and other smart grid facilities. Unless there is a separate capital quantity index for these facilities, the surge in capex that they entail is captured by the capital quantity index but the subsequent rapid decline in these quantities due to their short service lives is not.
- After severe storms, some utilities have increased capex to replace damaged facilities and/or improve system reliability and resiliency.
- Capex for AMI has been encouraged in several states by capex trackers, while capex for reasons other than AMI has been encouraged in a few states (e.g., Illinois, Massachusetts, and Ohio) by capex trackers or formula rates.

[2] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Berkeley Lab Report, July 2017, p. 6.4.

Table SEC-1a

Comparison of TFP trends from LBNL and Modified NERA Studies[1]

	LBNL[2]			Modified NERA Study[3]
Year	**O&M**	**Capital**	**TFP**	**TFP**
1973	na	na	na	1.09%
1974	na	na	na	2.35%
1975	na	na	na	3.39%
1976	na	na	na	1.50%
1977	na	na	na	1.16%
1978	na	na	na	0.65%
1979	na	na	na	1.66%
1980	-4.19%	1.24%	-0.49%	0.68%
1981	-2.42%	1.25%	0.17%	2.42%
1982	-1.20%	1.53%	0.87%	-0.02%
1983	-0.38%	0.98%	0.51%	0.41%
1984	-0.22%	1.79%	1.27%	0.59%
1985	-0.21%	1.37%	0.95%	0.39%
1986	0.88%	0.97%	0.91%	1.97%
1987	-0.12%	0.68%	0.44%	1.08%
1988	1.55%	0.24%	0.57%	2.43%
1989	0.00%	0.23%	0.26%	0.81%
1990	0.64%	-0.05%	0.18%	-0.15%
1991	0.58%	-0.32%	-0.03%	-0.19%
1992	1.61%	0.10%	0.48%	1.94%
1993	1.19%	0.12%	0.45%	-0.38%
1994	2.44%	0.29%	0.94%	0.99%
1995	3.58%	-0.04%	0.94%	2.68%
1996	0.67%	-0.13%	0.11%	-0.14%
1997	4.68%	0.39%	1.53%	0.72%
1998	0.73%	0.71%	0.67%	-1.03%
1999	2.24%	0.52%	1.08%	2.71%
2000	0.86%	0.73%	0.89%	-0.09%
2001	2.73%	0.61%	1.20%	3.30%
2002	2.73%	0.33%	0.79%	1.63%
2003	-1.50%	0.43%	-0.03%	-1.83%
2004	0.76%	0.22%	0.41%	2.91%
2005	-0.25%	0.09%	-0.07%	1.76%
2006	-1.07%	-0.21%	-0.52%	-0.11%
2007	0.00%	-0.02%	-0.12%	0.62%
2008	-2.06%	-0.09%	-0.99%	-0.42%
2009	2.73%	-0.46%	1.01%	1.74%
2010	-0.47%	0.05%	-0.27%	0.69%
2011	0.05%	0.50%	0.50%	-1.03%
2012	2.90%	0.58%	1.29%	0.05%
2013	0.40%	-0.05%	0.03%	0.97%
2014	-1.41%	0.56%	-0.03%	-0.61%
2015	na	na	na	0.09%
2016	na	na	na	-2.00%
Average Annual Growth				
1973 - 2016	**NA**	**NA**	**NA**	**0.85%**
1980 - 2014	**0.53%**	**0.43%**	**0.45%**	**0.79%**
1980 - 2000	**0.62%**	**0.60%**	**0.60%**	**0.85%**
2001 - 2014	**0.39%**	**0.18%**	**0.23%**	**0.69%**
2001 - 2016	**NA**	**NA**	**NA**	**0.49%**

Notes

[1]All growth rates are calculated logarithmically. For example, growth rate of X = $\ln(X_t/X_{t-1})$

[2]Table 4, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* (Lawrence Berkley National Laboratory, July 2017)

[3]The modified productivity trends were calculated with the following changes: initial capital stock was estimated by deflating gross plant values with 33-year triangular weighted averages of construction cost indexes; the average service life was assumed to be 37 years, a labor quantity correction was performed, improperly handled companies involved in mergers were removed, and the number of retail customers was used as the output variable.

- Smart grid, resilience, and replacement have improved distribution system capabilities, but these increases are difficult to measure. Recent productivity research and testimony for Hydro One by Power System Engineering suggests that the increase in that company's measured productivity due to improvements in safety and reliability has been substantial.[3]
- Table 1 in Dr. Lowry's report shows that growth in the number of customers served by utilities in NERA's sample averaged 1.6% annually from 1973-2000 and 0.90% from 2001-2016. This has reduced opportunities for distributors to realize scale economies.

Dr. Lowry shows in Table 6 of his report that the productivity growth of US gas utilities has been somewhat more negative than that of investor-owned US power distributors. Some of the forces slowing gas utility productivity growth have been similar to those facing power distributors.

- US gas utilities have also experienced declining R&C average use due to CDM programs, sluggish economic growth, and tighter appliance efficiency standards and building codes. Table SEC-1b, drawn from our recent Berkeley Lab report, shows that declines in average use have been *more* pronounced in gas distribution, and began earlier.
- Several gas utilities have installed advanced metering infrastructure.
- Growth in the number of customers served by many gas utilities has slowed considerably, and this has reduced the realization of scale economies. Scale economies are, if anything, more important in gas distribution than in power distribution.

Other reasons for slow gas utility productivity growth are somewhat different than those facing power distributors.

- Some gas utilities in the eastern and north central states still have a substantial amount of cast iron and/or bare steel pipe.
- Advanced system age seems to have a greater impact on operation and maintenance expenses in gas distribution than in power distribution, and raises special safety concerns in addition to reliability concerns.
- The US Pipeline and Hazardous Materials Safety Administration ("PHMSA") has mandated increased attention to gas pipeline safety. For example, it required development and implementation of integrity management ("IM") programs for gas transmission lines beginning in 2004 and required similar programs for gas distribution lines beginning in 2011.[4]

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[3] OEB Proceeding EB-2017-0049, Exhibit A-3-2, Attachment 1, *Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry*, prepared by PSE, Filed March 31, 2017.

[4] The GT IM Rule resulted in regulations (49 CFR Part 192, Subpart O) which specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCAs") within the United States. These HCAs include certain populated and occupied areas. Operators were given until December 17, 2004 to write and implement their IM programs. https://primis.phmsa.dot.gov/gasimp/index.htm. PHMSA published the final rule establishing IM requirements for gas distribution pipeline systems on December 4, 2009 (74 FR 63906). The effective date of the rule

- Partly because safety is at issue, quite a few state regulators have been willing to approve capital cost trackers or formula rates for US gas utilities, and these mechanisms encourage capex.

Please also note that negative capital productivity growth is found in other industries as well and is often offset by positive growth in the productivity of OM&A inputs.

Table SEC.1b

	Average Annual Electricity Use					Average Annual Natural Gas Use					GDPPI Inflation[4]		Summary Attrition Indicators	
	Residential[1]		Commercial[1]		Average	Residential[2]		Commercial[3]		Average				
	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Electric	Natural Gas
Multiyear Averages					[A]					[B]		[C]	[C]-[A]	[C]-[B]
1927-1930	478	7.06%	3,659	6.67%	6.86%	NA	NA	NA	NA	NA	9.71	-3.92% [5]	-10.79%	NA
1931-1940	723	5.45%	4,048	2.00%	3.73%	NA	NA	NA	NA	NA	7.99	-1.59%	-5.31%	NA
1941-1950	1,304	6.48%	6,485	5.08%	5.78%	NA	NA	NA	NA	NA	11.37	5.26%	-0.52%	NA
1951-1960	2,836	7.53%	12,062	6.29%	6.91%	NA	NA	NA	NA	NA	16.04	2.42%	-4.49%	NA
1961-1972	5,603	5.79%	31,230	8.79%	7.29%	125	1.78% [6]	726	3.97% [6]	2.88% [6]	20.35	2.98%	-4.32%	0.10% [7]
1973-1980[8]	8,394	2.03%	50,576	2.53%	2.28%	117	-2.22%	764	-0.63%	-1.42%	34.74	7.18%	4.90%	8.61%
1981-1986[8]	8,820	0.12%	54,144	0.81%	0.46%	98	-2.67%	651	-3.84%	-3.26%	54.22	4.57%	4.11%	7.82%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%	93	-1.25%	631	1.33%	0.04%	63.32	3.33%	1.49%	3.29%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%	88	-0.37%	639	0.30%	-0.04%	75.70	2.03%	0.62%	2.07%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%	77	-2.12%	594	-1.55%	-1.83%	89.83	2.47%	1.79%	4.30%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%	72	0.58%	597	1.75%	1.17%	103.53	1.60%	1.90%	0.43%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, Historical Natural Gas Annual 1930 Through 1999 (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014).

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers, Revised October 28, 2016.

[5] Growth rate is for 1930 only. Data are not available before 1929.

[6] Levels are for 1967-1972 and growth rates are for 1968-1972. Data are not available before 1967.

[7] Note that the growth rates used to compute this value cover different periods.

[8] Shaded years had unusually unfavorable business conditions.

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was February 12, 2010, resulting in IM regulations for gas distribution pipelines (49 CFR Part 192, Subpart P). Operators were given until August 2, 2011 to write and implement their distribution integrity management programs (DIMPs). https://primis.phmsa.dot.gov/dimp/

L1.SEC.2

2. [Page 26, 33, 34] Does Table 3 estimate the impact on past US power or gas productivity trends (based on volumes as an output, as NERA proposes) of declining average use? If so, is that estimate the difference between the last and second last lines, e.g. +0.67% for 2001-2016, regardless of which of the other adjustments are made? To what extent, if any, is the order of the adjustments in Table 3 relevant to the quantum of each increment?

Response to SEC-2: The following response was provided by PEG.

Table 3 of Dr. Lowry's report shows a sequence of changes to the sample and input and output quantity specifications in NERA's power distribution productivity study. The last step is replacement of NERA's volumetric output index with the number of customers served. For the 2001-2016 sample period, productivity accelerates by 67 basis points. When the replacement of the output index is the only change undertaken, productivity accelerates by 64 basis points. Hence, the sequence of upgrades does have a modest impact on the incremental impact of each upgrade.

L1.SEC.3

3. [Page 33] Why is it not appropriate to use the estimate of +0.85% productivity, i.e. the corrected NERA results, for the Applicants going forward.

Response to SEC-3: The following response was provided by PEG.

Despite the upgrades to NERA's methodology PEG undertook, PEG does not believe that results using NERA's full sample period provide the best basis for setting an X factor for the Amalco. The full sample period may be too long to properly reflect the current long run power distribution productivity trend. Additionally, PEG remains concerned about the sensitivity of a simple one hoss shay capital cost specification (which has one asset category) to the average service life assumption. The Amalco, in any event, provides gas transmission, storage, distribution, and customer services and not power distribution services.

L1.SEC.4

4. [Page 35, 36, 49] Please discuss whether the -1.70% capital productivity for Enbridge 1993-2016, or -2.33% capital productivity for Enbridge 2001-2016 reflect past capital spending in excess of the Board's ICM thresholds. Please estimate an adjustment to the ICM threshold formula that would correct for this negative capital productivity, i.e. set the ICM threshold going forward on the basis of past spending levels rather than "zero- productivity" spending levels.

Response to SEC-4: The following response was provided by PEG.

Recent high levels of capex have bolstered the Applicants' rate bases, and this should raise the materiality threshold. The X factor for capital revenue could in principle be based on the recent historical trend in the capital productivity of the Applicants. One variant on this theme would be the K-bar approach used in Alberta, which fixes a K factor based on expected capital cost underfunding assuming continuation of the utility's recent historical plant additions. The AUC stated in approving this approach that

> . . . the Commission does not approve a method of calculating base K-bar that involves a forecast component. The Commission also agrees with those parties that took the position that using an average of historical actuals involves less regulatory burden than the testing of a full 2018 forecast for all capital programs. Accordingly, the Commission will, instead, rely upon a formulaic approach to determine the 2018 projected capital additions to be included in the base K-bar accounting test.[5]

Another variant, with California precedents, would have capital revenue recover projected cost, without any resort to indexing, where recent historical levels of plant additions are assumed to continue. All three of these approaches would reduce regulatory cost but generate weak capex containment incentives in repeated applications.[6] Please see our response to SEC-5 for an alternative way to reduce the X factor for capital revenue which has better incentive properties.

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[5] Alberta Utilities Commission, *2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities,* Decision 20414-D01-2016, December 16, 2016, p. 64.
[6] PEG noted in its 2017 LBNL study that California was one state using multiyear rate plans that it surveyed where power distributor growth was below the national norm.

L1.SEC.5

5. [Page 24, 36, 47] Please discuss whether, given the proposal for an ICM and protections against volume declines, it is appropriate to use partial factor productivity for OM&A to adjust non-capital revenue requirement. In the event that is a viable option, please discuss options for the Board to address capital revenue requirement that would be consistent with an OM&A driven productivity factor, and would avoid double-counting of capex in the formula.

Response to SEC-5: The following response was provided by PEG.

PEG believes that separate treatment of OM&A and capital revenue is an option meriting serious consideration for the Amalco and other utilities that chronically seek supplemental capital revenue. PEG's gas utility productivity study in this proceeding provides the basis for an Inflation – (0.33 + Stretch) escalation formula for OM&A revenue and an Inflation – (-.87% + Stretch) escalation formula for capital revenue. Use of these two escalators, instead of an Inflation – (0.00 + Stretch) escalator for all revenue, would slow growth in OM&A revenue. Capital revenue might not change, but the need for an ICM to supplement capital revenue would diminish. Separate ratemaking treatment of OM&A and capital revenue is a longstanding feature of incentive regulation in Australia, British Columbia, California, and Hawaii.

L1.SEC.6

6. [Page 39] What percentage of US customer service and information expenses in gas distribution is utility CDM programs?

Response to SEC-6: The following response was provided by PEG.

The share of CDM expenses in the customer service and information expenses of gas US utilities is unknown but likely varies widely, due in part to varying state policies concerning CDM.

L1.SEC.7

7. [Page 40] Both the US and Canadian results show negative capital productivity. Aside from the new US asset integrity rules, what are the reasons why capital spending in gas distribution has negative productivity? To what extent, if any, are those reasons applicable in Ontario. Are those reasons expected to continue in the future?

Response to SEC-7: The following response was provided by PEG.

Please see our response to SEC.1 for some explanations of negative gas utility TFP growth.

Some of these conditions are also likely to face the Applicants during the proposed IRM.

- Gas safety regulation in the US and Canada is broadly similar in nature. Both require leak management and integrity management programs at the distribution and transmission levels. Both the US and Canada allow for state/provincial regulation of safety, while interstate/interprovincial and international pipelines are regulated at the federal level. In the US, federal regulation is viewed as the minimum regulatory requirement and is often supplemented by state regulations, while in Canada, most provincial regulators adopt the national standard with some modifications.

  There are several other items that suggest similarity in pipeline safety regulations between the US and Canada. In 2005 the PHMSA and National Energy Board ("NEB") signed a Memorandum of Understanding "to enhance cooperation and coordination between [the NEB and PHMSA] for the purpose of improving pipeline safety in both Canada and the United States." Union Gas' most recent annual report suggests that changes in US pipeline safety regulation may affect the regulations it faces.
- R&C average use may continue to decline.
- The IRM may provide funding for high capex.
- The Applicants forecast customer growth that is similar to that experienced by utilities in the gas productivity study.

On the other hand,

- Enbridge does not have much cast iron or bare steel main.
- The merger of Enbridge and Union could achieve material scale economies.

L1.SEC.8

8. [Page 42] What are the likely implications of future productivity over a ten year rebasing deferral period of high past capital spending (i.e. negative capital productivity)? Is it possible to estimate the quantitative impact on productivity of such a pattern? To what extent, if any, is it reasonable to expect capital productivity to revert to zero over time?

Response to SEC-8: The following response was provided by PEG.

Since the gas utility business is highly capital-intensive, a period of high capital spending can easily drive *total factor* productivity growth as well as *capital* productivity growth negative. As surge capex depreciates, however, it slows cost growth and accelerates productivity growth when a geometric decay or COS capital specification is employed in the productivity research. After the capex surge ends, *positive* capital and total factor productivity growth are both quite possible. The long run productivity growth of the industry can never be achieved if substandard productivity growth alternates with normal productivity growth.

To learn more about this phenomenon, PEG examined the TFP growth patterns of gas utilities in our sample that experienced capex surges. We first identified companies that experienced three years of capital quantity growth that exceeded their capital quantity trends for the full sample period by at least 140% on average. We then measured the average TFP growth after the surges until and unless another surge began. We found that, whereas TFP growth averaged -0.39% for the full sample period for all companies, it averaged 0.00% in the aftermath of capex surges.