TECHNICAL CONFERENCE UNDERTAKING RESPONSES OF PACIFIC ECONOMICS GROUP RESEARCH LLC TO HYDRO OTTAWA LIMITED

UNDERTAKING JT4.16

Undertaking:

To produce what PEG has filed publicly in the Hawaiian Electric proceeding.

Response:

Please see Undertaking JT4.16 Attachment for the 4 PEG reports filed in the Hawaiian Electric proceeding 2018-0088.

New X Factor Research for HECO

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Table of Contents

1. Introduction

Hawaii's Public Utilities Commission ("the Commission") is considering in Docket No. 2018-0088 the design of new multiyear rate plans ("MRPs") for Hawaiian Electric Company ("HECO") and its neighbor-island subsidiary utilities (the "HECO Companies" or "Companies"). The Commission ruled in Decision and Order No. 36326 ("D&O 36326"),[1] filed May 23, 2019, that each plan will feature an annual revenue adjustment ("ARA") that is driven by the formula

$$ARA = Inflation - (X + Customer\ Dividend) + Z.$$

The cost of some of the Companies' capital expenditures ("capex") will be separately addressed by major project interim recovery ("MPIR") trackers.

The value of the "X factor" in this formula is a key issue in the proceeding. In its initial comprehensive proposal filed on 14 August 2019 and its updated proposal filed on January 15, 2020, HECO proposed a **-1.41%** value for X and a **0.22%** Customer Dividend. This proposal was supported by analysis and empirical work by Pacific Economics Group Research LLC ("PEG") on the cost trends of mainland vertically integrated electric utilities ("VIEUs"). This work was detailed in an August report entitled *Designing Revenue Adjustment Indexes for Hawaiian Electric Companies*.[2] HECO has indicated that it intends to update its proposed value of X to -**1.32%** based on corrections provided by PEG which were presented in a Revenue Working Group ("RWG") meeting on March 13, 2020.

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[1] In D&O 36326, the Commission established the regulatory principles, goals, and outcomes to guide Phase 2, and identified a portfolio of specific PBR mechanisms for prioritized examination and development. D&O 36326 pages 1-2.

[2] The updated comprehensive proposal states that: "The proposed value of X is -1.41%, pending further evaluation of the X-factor and financial analyses of the MRP proposals. In PEG's "featured" run, the indicated Kahn X-factor was **-1.04**% for the full 1997-2017 sample period. The X-factor was even more negative for more recent sample periods, falling to **-1.41**% for the last fifteen years (2003-2017) and to **-2.35**% for the last 10 years (2008-2017). In these calculations, PEG found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. Given the increasingly negative value of the X-factor, use of the value for the last 15 years, rather than the value for the last 10 years, is somewhat conservative." Updated Comprehensive Proposal page 24.

Debate over the appropriate X factor has ensued during the months since the August filings of the parties. Questions that parties have raised include the following.

- Is the experience of VIEUs like those in PEG's study germane to the establishment of an X factor for HECO?
- Is HECO's claimed need for replacement capital expenditures ("repex") in the next five years a consideration in setting X?
- Should the X factor be adjusted to reflect the operations of the MPIR trackers?

The document entitled "Commission Staff Guidance for PBR Phase 2 Working Group Meetings, February 2020" states that "Parties are encouraged to include in their [future revised] proposals further analyses of the conceptual definition and quantification of the ARA "X" factor included in the January proposal updates…It should be clear how the definition and determination of the ARA formula relates to and is appropriate for application of the MPIR provisions."

Pacific Economics Group ("PEG") has since August conducted some new research that complies with Staff's request and sheds light on the questions above and the appropriate X factors for the HECO Companies. Notable tasks included the following.

- We have used new econometric cost research to study the drivers of growth in the multifactor productivity[3] ("MFP") of vertically integrated electric utilities and to make custom output and MFP growth projections for the HECO Companies.
- We computed more detailed X factor results using index research.
- We gathered comparative statistics on the age of HECO's system.

This is a report on our new research. We begin by reprising pertinent results from our August report. There follows a discussion of our latest research and salient results. There are brief concluding remarks.

[3] Technical terms are underlined at their first mention throughout this report.

2. Key Results from Our August Report

This section reprises key findings from our August Report in order to provide context for the discussion of our new research for HECO.

2.1 Basic Principles

A theoretical result from a classic paper by Denny, Fuss, and Waverman should inform the design of ARA formulas:

growth Cost = growth Input Prices – growth MFP + growth Outputs.[4] [1]

Here *Input Prices* is an input price index. *Outputs* is an index of output growth that, if multidimensional, has weights for subindexes which reflect their relative cost impacts.[5] Econometric estimates of the elasticities of cost with respect to output variables provide a sensible basis for these weights.[6] *MFP* is a multifactor productivity index that is calculated with a consistent cost-based output index. Since vertically integrated electric utilities like HECO provide various services (e.g., generation, transmission, and distribution), and the ARA will address transmission costs, multidimensional indexes are useful for measuring their output.

This result would provide the basis for the following ARA formula for HECO.

growth Revenue = growth Input Prices – ($\overline{MFP}$*+ Customer Dividend*) *+ growth Outputs*^{HECO}

where $\overline{MFP}$ is an appropriate MFP growth target. It suggests that ARA formulas should by some means reflect actual or expected growth in the output of each subject utility. This could take the form of an explicit scale escalator or an X factor adjustment. We noted in the August

[4] 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.

[5] Output indexes with subindex weights that reflect the relative *revenue* impacts of *billing determinants* are used in the design of *price* cap indexes.

[6] The elasticity of cost with respect to an output variable Y is the percentage change in cost that results from a 1% change in Y.

report that a sizable majority of revenue cap indexes approved in North America include explicit scale escalators. Most of these indexes have applied to energy distributors, and allowed revenue has been escalated for customer growth. If the ARA does not compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit customer dividend in the formula.

Some readers may find an alternative demonstration of the relevance of output growth to the design of ARA formulas persuasive. A key result of index theory is that cost growth is the sum of the growth of an appropriate input price index and input quantity index ("*Input Quantities*").

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Input Quantities}. \qquad [2]$$

If a revenue cap index compensates a utility only for input price inflation less MFP growth, it will therefore generally not provide sufficient compensation for input *quantity* growth even if the MFP growth trend is zero.

2.2 Inflation Measure Issues

If an ARA formula uses the gross domestic product price index ("GDPPI") as the inflation measure, the X factor should reflect the tendency of the GDPPI to track utility input prices accurately, not just the industry productivity trend. This can be accomplished with the following X factor formula

$$X = \textit{trend } MFP_{Industry} + (\textit{trend GDPPI} - \textit{trend Input Prices}_{Industry}) \qquad [3]$$

where the term in parentheses is the inflation differential and $\textit{Input Prices}_{Industry}$ is a utility industry input price index. The inflation differential tends to be negative due to the sluggish growth that the GDPPI has displayed for many years, and this differential can be as much or more important than the productivity trend in determining X.

It can also be shown that

$$\textit{trend GDPPI} = \textit{trend Input Prices}_{Economy} - MFP_{Economy} \qquad [4]$$

where $\textit{Input Prices}_{Economy}$ and $MFP_{Economy}$ are the input price and *MFP* indexes of the economy.

Relations [3] and [4] imply that

$X = (trend\ MFP_{Industry} - trend\ MFP_{Economy}) - (trend\ Input\ Prices_{Economy} - Input\ Prices_{Industry})$. [5]

The X factor can thus be expressed equivalently as the sum of a productivity differential and an input price differential. Relation [5] implies that X is reduced by the MFP growth of the economy, and this has tended to be material in the United States for many years.

Our August report documented numerous cases where regulators based X factors on productivity differentials. For example, the Department of Public Utilities ("DPU") in Massachusetts has used this approach in two recent proceedings that approved MRPs for power distributors.[7] Both plans feature revenue cap indexes with the GDPPI as the inflation measure.

2.3 Kahn Method Research

For our August report, PEG sidestepped these relatively complicated X factor formulas and instead presented the results of simpler "Kahn method" cost trend research. The basic idea is to find the value of X that would cause the trends in hypothetical ARA indexes to track the cost trends of the utilities on average during the sample period. A familiar approach to calculating capital costs can be used since capital cost trends do not need to be decomposed into price and quantity trends. The study used publicly available data from 45 mainland VIEUs in the econometric and Kahn method calculations. The full sample period considered was the 21 years from 1997 to 2017.

A multidimensional scale index with econometric cost elasticity weights that are appropriate for VIEUs was employed in these calculations. This reduces the indicated value of X. Since the Commission's approved ARA formula does not include a scale index, the need for an adjustment to the X factor for output growth remains an issue in the choice of an X factor.

[7] Since our August report, the Department approved a new MRP for power distributor services of National Grid. See Massachusetts D.P.U. 18-150.

The indicated X factor from this research was materially negative for all sample periods that we considered. A negative inflation differential, not negative productivity growth, was the chief source of the negative X factor. The indicated X factors were more negative for more recent sample periods. The declining value of X was mainly due to accelerated capital cost growth since 2007 which occurred despite slowdowns in GDPPI and output growth. These results suggest that the sample period is a key consideration in the choice of X factors for the HECO companies. HECO proposed to base X on our Kahn method results for the 15-year 2003-2017 period. The Massachusetts DPU chose a fifteen-year sample period to set X in both of its recent Massachusetts PBR proceedings.

2.4 Corrections to Kahn Method Calculations

In March 2020, PEG provided corrections to its X factor calculations using the Kahn methodology. The corrections can be summarized as follows. A minor correction was needed due to a few missing transmission miles observations in 1995, which affected the 1996 midyear miles, which in turn affected the 1997 growth rate. The impact was 2 basis points on the X factor for the longest sample period. The other correction was to the 2016 and 2017 cost data. PEG corrected the depreciation and amortization data to reflect only electric operations. PEG had previously used values for *total* utility operations inadvertently. This error affected only the data of companies with gas distribution operations. Results for all three sample periods changed modestly.

The corrected Kahn method results are provided in Tables 1-3 below. For the fifteen-year 2003-2017 period, the indicated X factor was reduced from -1.41% to **-1.32%**. Over this same period, PEG estimates in Table 3 that the multifactor productivity ("MFP") trend that is implicit in these calculations was reduced from -0.54% to -0.45%. It remains the case that a negative inflation differential, not negative productivity growth, was the chief source of the negative X-factor.

Reasons advanced in our August report for the decline in MFP growth included the following:

- slowing growth in the demand for electric utility services;

Table 1

Corrected U.S. VIEU Kahn X Factor Calculations [1,2]

		Operating Scale								Indicated X Factor	
Year	Total Cost	Retail Customers	Mid-Year Average Generation Capacity	Fossil Steam and Other Generation Volume	Mid-Year Average Transmission Line Miles	Ratcheted Maximum Peak Demand	Scale Index[3]	GDPPI Inflation		Using Scale Index	Using Customers
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]		[G]+[H]-[A]	[B]+[H]-[A]
1997	3.82%	1.80%	0.62%	5.16%	0.34%	3.74%	2.02%	1.70%		-0.10%	-0.31%
1998	3.45%	1.92%	0.09%	5.60%	0.32%	3.09%	1.86%	1.08%		-0.51%	-0.45%
1999	1.06%	1.40%	-0.68%	4.25%	0.38%	2.75%	1.30%	1.42%		1.67%	1.77%
2000	6.21%	2.07%	-1.49%	2.99%	-0.68%	2.15%	1.07%	2.25%		-2.89%	-1.90%
2001	3.16%	1.51%	0.55%	1.39%	-1.14%	1.55%	1.03%	2.26%		0.14%	0.61%
2002	2.53%	1.40%	4.69%	-1.61%	0.08%	1.23%	1.77%	1.52%		0.76%	0.39%
2003	2.43%	1.33%	4.58%	-1.09%	0.19%	1.86%	1.88%	1.98%		1.44%	0.89%
2004	2.90%	1.45%	2.03%	-0.11%	-0.07%	0.36%	1.12%	2.71%		0.92%	1.26%
2005	3.79%	1.51%	2.52%	1.44%	-0.31%	2.83%	1.81%	3.17%		1.20%	0.89%
2006	4.06%	0.20%	4.26%	1.07%	-0.93%	1.82%	1.40%	3.02%		0.36%	-0.85%
2007	6.05%	1.39%	3.26%	2.33%	0.10%	1.86%	1.87%	2.63%		-1.55%	-2.02%
2008	4.54%	1.04%	2.58%	2.45%	1.21%	0.70%	1.46%	1.91%		-1.16%	-1.59%
2009	5.10%	0.60%	2.14%	-4.23%	0.98%	0.69%	0.63%	0.78%		-3.69%	-3.71%
2010	7.85%	0.52%	2.21%	-0.06%	1.03%	1.15%	1.03%	1.22%		-5.59%	-6.11%
2011	4.05%	0.44%	1.70%	3.11%	0.72%	1.06%	1.09%	2.04%		-0.92%	-1.56%
2012	2.36%	0.59%	1.39%	-2.13%	1.52%	0.40%	0.61%	1.82%		0.07%	0.05%
2013	4.30%	0.78%	1.13%	1.06%	1.05%	0.31%	0.82%	1.60%		-1.88%	-1.92%
2014	5.41%	0.81%	1.13%	2.33%	0.67%	1.13%	1.05%	1.78%		-2.57%	-2.82%
2015	4.26%	1.01%	1.59%	-1.14%	1.06%	0.73%	0.93%	1.06%		-2.27%	-2.18%
2016	3.97%	1.08%	-0.60%	-2.96%	1.08%	0.21%	0.21%	1.31%		-2.45%	-1.58%
2017	2.63%	0.85%	-0.96%	-1.69%	0.66%	0.16%	0.08%	0.89%		-1.66%	-0.89%
Average Annual Growth Rates											
1997-2017	4.00%	1.13%	1.56%	0.87%	0.39%	1.42%	1.19%	1.82%		**-0.99%**	**-1.05%**
2003-2017	4.25%	0.91%	1.93%	0.03%	0.60%	1.02%	1.07%	1.86%		**-1.32%**	**-1.47%**
2008-2017	4.45%	0.77%	1.23%	-0.33%	1.00%	0.65%	0.79%	1.44%		**-2.21%**	**-2.23%**

Notes:

[1]Costs and volumes that are inapplicable to the HECO Companies were excluded from this analysis. These include the costs, capacities, and volumes of conventional hydraulic, pumped storage hydraulic, and nuclear generation.

[2]All values shown are an average of annual (logarithmic) growth rates of variables in a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. Elasticity weights were those displayed in Table 7 of our August report. The formula is growth Scale [G] = 40.9% x [B] + 23.2% x [C] + 7.9% x [D] + 9.4% x [E] + 18.6% x [F].

Table 2

Impact of Various Cost Components on Kahn X Factor Results (Corrected)[1,2]

	GDPPI[3]	Operating Scale		Cost							Kahn X Factors by Cost Category					
				Capital					O&M	Total[8]						
Year		Retail Customers	Scale Index[4]	Rate of Return[5]	Rate Base[6]	Return on Rate Base	Depreciation and Amortization	Total[7]			Rate Base	Return on Rate Base	Depreciation and Amortization	Capital Cost	O&M Cost	Total Cost
	[A]		[B]	[C]	[D]	[E]=[C]+[D]	[F]	[G]	[H]	[I]	[A]+[B]-[D]	[A]+[B]-[E]	[A]+[B]-[F]	[A]+[B]-[G]	[A]+[B]-[H]	[A]+[B]-[I]
1997	1.71%	1.80%	2.02%	0.20%	2.75%	2.95%	5.21%	3.89%	3.77%	3.82%	0.98%	0.78%	-1.48%	-0.16%	-0.04%	-0.10%
1998	1.08%	1.92%	1.86%	1.46%	1.50%	2.96%	2.21%	2.73%	4.32%	3.45%	1.43%	-0.03%	0.73%	0.21%	-1.38%	-0.51%
1999	1.42%	1.40%	1.30%	-5.68%	1.72%	-3.96%	3.55%	-1.16%	4.56%	1.06%	1.00%	6.68%	-0.82%	3.88%	-1.83%	1.67%
2000	2.25%	2.07%	1.07%	5.04%	2.44%	7.48%	4.51%	6.38%	5.73%	6.21%	0.88%	-4.16%	-1.19%	-3.06%	-2.41%	-2.89%
2001	2.26%	1.51%	1.03%	-2.96%	3.37%	0.40%	4.05%	1.86%	4.99%	3.16%	-0.08%	2.89%	-0.76%	1.43%	-1.70%	0.14%
2002	1.52%	1.40%	1.77%	-2.50%	4.42%	1.92%	3.04%	2.34%	2.65%	2.53%	-1.13%	1.36%	0.25%	0.94%	0.63%	0.76%
2003	1.98%	1.33%	1.88%	-2.59%	4.89%	2.29%	3.43%	2.73%	1.79%	2.43%	-1.02%	1.57%	0.43%	1.13%	2.08%	1.44%
2004	2.71%	1.45%	1.12%	-2.22%	4.71%	2.48%	1.96%	2.17%	3.83%	2.90%	-0.88%	1.34%	1.86%	1.66%	-0.01%	0.92%
2005	3.17%	1.51%	1.81%	-2.41%	4.57%	2.16%	4.68%	3.18%	4.60%	3.79%	0.41%	2.82%	0.30%	1.80%	0.38%	1.20%
2006	3.02%	0.20%	1.40%	-2.23%	4.88%	2.65%	4.08%	3.26%	4.91%	4.06%	-0.45%	1.77%	0.34%	1.16%	-0.49%	0.36%
2007	2.63%	1.40%	1.87%	-1.71%	6.14%	4.43%	6.29%	5.35%	6.63%	6.05%	-1.64%	0.07%	-1.79%	-0.85%	-2.13%	-1.55%
2008	1.91%	1.04%	1.46%	0.58%	8.07%	8.65%	2.41%	5.92%	3.27%	4.54%	-4.70%	-5.28%	0.97%	-2.55%	0.11%	-1.16%
2009	0.78%	0.60%	0.63%	-0.39%	9.65%	9.26%	7.45%	8.59%	0.66%	5.10%	-8.25%	-7.86%	-6.04%	-7.19%	0.75%	-3.69%
2010	1.22%	0.52%	1.03%	-0.35%	10.19%	9.84%	7.46%	8.84%	6.06%	7.85%	-7.94%	-7.58%	-5.20%	-6.59%	-3.81%	-5.59%
2011	2.04%	0.44%	1.09%	-1.48%	8.06%	6.58%	7.79%	7.17%	-0.26%	4.05%	-4.93%	-3.45%	-4.66%	-4.04%	3.39%	-0.92%
2012	1.82%	0.59%	0.61%	-2.22%	7.12%	4.90%	2.18%	3.72%	0.28%	2.36%	-4.69%	-2.47%	0.26%	-1.29%	2.16%	0.07%
2013	1.60%	0.78%	0.82%	-1.03%	6.54%	5.51%	4.58%	5.06%	2.96%	4.30%	-4.12%	-3.09%	-2.16%	-2.63%	-0.53%	-1.88%
2014	1.78%	0.81%	1.05%	-1.89%	6.86%	4.97%	5.13%	5.03%	6.13%	5.41%	-4.03%	-2.14%	-2.30%	-2.19%	-3.30%	-2.57%
2015	1.06%	1.02%	0.93%	1.10%	8.76%	9.86%	6.40%	8.51%	-2.61%	4.26%	-6.77%	-7.87%	-4.41%	-6.53%	4.60%	-2.27%
2016	1.31%	1.08%	0.21%	-3.54%	7.60%	4.06%	7.02%	5.24%	1.70%	3.97%	-6.08%	-2.54%	-5.50%	-3.73%	-0.18%	-2.45%
2017	0.89%	0.85%	0.08%	-0.69%	5.17%	4.48%	4.30%	4.40%	-0.82%	2.63%	-4.19%	-3.51%	-3.32%	-3.42%	1.79%	-1.66%
Average Annual Growth Rates																
1997-2017	1.82%	1.13%	1.19%	-1.21%	5.69%	4.47%	4.65%	4.53%	3.10%	4.00%	**-2.68%**	**-1.46%**	**-1.64%**	**-1.52%**	**-0.09%**	**-0.99%**
2003-2017	1.86%	0.91%	1.07%	-1.40%	6.88%	5.48%	5.01%	5.28%	2.61%	4.25%	**-3.95%**	**-2.55%**	**-2.08%**	**-2.35%**	**0.32%**	**-1.32%**
2008-2017	1.44%	0.77%	0.79%	-0.99%	7.80%	6.81%	5.47%	6.25%	1.74%	4.45%	**-5.57%**	**-4.58%**	**-3.24%**	**-4.02%**	**0.50%**	**-2.21%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]The annual growth rate of the U.S. Gross Domestic Product Price Index ("GDPPI").

[4] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 7 in our August 2019 report. The formula becomes *growth* Scale [B] = 40.9% x [*growth* Retail Customers] + 23.2% x [*growth* Generation Capacity] + 7.9% x [*growth* Generation Volume] + 9.4% x [*growth* Transmission Line Miles] + 18.6% x [*growth* Ratcheted Peak Demand].

[5]The annual growth rate of an average of the Edison Electric Institute's "Rate Case Summary" ROE and the embedded cost of debt from FERC Form 1 data of a nationally representative sample of electric utilities.

[6]The growth rate of the average value of rate base at the start and end of the year.

[7]The annual growth rate in total capital cost does not equal the sum of the annual growth rates of return on rate base [E] and depreciation and amortization [F].

[8]The annual growth rate in total cost does not equal the sum of the annual growth rates of capital cost [G] and O&M cost [H].

Table 3

Decomposing the Kahn X Factor (Corrected)

Year	Kahn X Factor (with scale index)	GDPPI	Industry Input Price Growth	Inflation Differential	Residual X Resulting from Productivity and Other Factors
	[A]	[B]	[C]	[D] = [B] - [C]	[E] = [A] - [D]
1997	-0.10%	1.70%	3.72%	-2.01%	1.92%
1998	-0.51%	1.08%	3.98%	-2.90%	2.39%
1999	1.67%	1.42%	0.61%	0.81%	0.85%
2000	-2.89%	2.25%	5.71%	-3.46%	0.57%
2001	0.14%	2.26%	2.04%	0.22%	-0.08%
2002	0.76%	1.52%	1.98%	-0.47%	1.22%
2003	1.44%	1.98%	2.10%	-0.12%	1.55%
2004	0.92%	2.71%	2.33%	0.37%	0.55%
2005	1.20%	3.17%	2.30%	0.87%	0.32%
2006	0.36%	3.02%	2.89%	0.13%	0.23%
2007	-1.55%	2.63%	3.08%	-0.45%	-1.10%
2008	-1.16%	1.91%	4.00%	-2.09%	0.93%
2009	-3.69%	0.78%	2.99%	-2.20%	-1.48%
2010	-5.59%	1.22%	3.01%	-1.79%	-3.81%
2011	-0.92%	2.04%	2.70%	-0.65%	-0.26%
2012	0.07%	1.82%	2.41%	-0.59%	0.67%
2013	-1.88%	1.60%	2.42%	-0.81%	-1.06%
2014	-2.57%	1.78%	2.46%	-0.68%	-1.89%
2015	-2.27%	1.06%	3.41%	-2.35%	0.09%
2016	-2.45%	1.31%	1.21%	0.10%	-2.54%
2017	-1.66%	0.89%	3.58%	-2.69%	1.03%

Average Annual Growth Rates

1997-2017	-0.99%	1.82%	2.81%	**-0.99%**	**0.00%**
2003-2017	-1.32%	1.86%	2.73%	**-0.86%**	**-0.45%**
2008-2017	-2.21%	1.44%	2.82%	**-1.38%**	**-0.83%**

- capital spending to reduce generation emissions and increase access to and reliance on renewable resources;
- increased need for replacement capital expenditures (aka "repex");
- increased use of advanced metering infrastructure and other "smart grid" equipment; and
- higher reliability and resiliency expectations.

2.5 Recent X Factor Precedents

Our MFP and X factor results are broadly in line with recent U.S. X factor precedents.

- The average itemized MFP growth target in U.S. MRPs with rate or revenue cap indexes is about -0.30%.
- The average X factor in the three current U.S. MRPs with rate or revenue cap indexes is about -1.50%.
- Several recent PBR plans in Ontario have featured a 0% MFP growth target.

2.6 Productivity Drivers

The Denny, Fuss, and Waverman paper also provides a method for identifying drivers of productivity growth which is based on cost theory. They found that MFP growth reflects technological change and reductions in inefficiency --- two important sources of improved cost efficiency --- but also has other drivers that include changes in output and various other external business conditions. Productivity indexes are therefore not pure measures of operating efficiency.

To better understand this result, consider that a productivity index is the ratio of an output index to an input index. The quantity of inputs that a utility uses depends on various external business conditions as well as its efficiency. Thus, productivity growth is sensitive to changes in business conditions as well as to changes in efficiency.

While the ratio of outputs to inputs intuitively seems like a pure efficiency measure, outputs are not the only external business conditions that drive cost. Suppose for example that utility cost is also a function of the number of trees in the service territory. We could then measure efficiency by taking the ratio of trees to the quantity of inputs. More efficient utilities would have higher scores. However, this metric would not control for the large differences that exist in the output of utilities in the sample.

3. New Econometric Research

3.1 Pertinent Results of Cost Theory

Economic theory reveals that the cost of an enterprise is a function of input prices, operating scale ("*Outputs*", which may be multidimensional), and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

$$Cost = f(Input\ Prices,\ Outputs,\ Other\ Variables,\ Time). \quad [6]$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$

$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \quad [7]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of model parameters. This model has a double log functional form in which cost and the values of business condition variables are logged. With this form, parameters $\hat{\beta}_1$ to $\hat{\beta}_4$ are also estimates of the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model. This parameter would capture the typical net effect on utility cost trends of technological progress and changes in cost driver variables that are excluded from the model.

Econometric cost research has several uses in the determination of X factors for the HECO companies. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$\textit{growth Outputs}^C = [\hat{\beta}_1 / (\hat{\beta}_1 + \hat{\beta}_2)] \times \textit{growth Output}_1 +$$

$$[\hat{\beta}_2 / (\hat{\beta}_1 + \hat{\beta}_2)] \times \textit{growth Output}_2. \qquad [8]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. An index of this kind can be used in MFP and Kahn method research. It can also serve as the scale escalator of an ARA formula. If the formula lacks such an escalator, the expected growth in the output index during the term of the MRP can provide the basis for an X factor adjustment.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [7], growth in a company's MFP can be decomposed as follows.

$$\textit{growth MFP} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times \textit{growth Outputs}$$

$$- (\hat{\beta}_3 \times \textit{growth Other}_1 + \hat{\beta}_3 \times \textit{growth Other}_2) - \hat{\beta}_T. \qquad [9]$$

The first term in [9] is the economies of scale that are realized due to output growth. These economies are greater the smaller is the sum of the cost elasticities with respect to output ($\hat{\beta}_1 + \hat{\beta}_2$) and the greater is output index growth. Relation [9] also shows that a change in the value of a business condition variable like $Other_1$ raises cost it also slows MFP growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) MFP growth. Formulas like [8] and [9] can be generalized to models with additional outputs and other business condition variables.

Econometric cost research and an equation like [9] can be used to identify MFP growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [9] can also provide the basis for MFP growth projections that are specific to the business conditions of a utility that will be operating under PBR. For example, we can make projections that are specific to HECO during the four likely indexing years (2021-2024) of its PBR plan. These are effectively projections of the MFP growth of typical utility managers if faced with HECO's business conditions.

For the simple model detailed in equation [9] the MFP growth projection formula would be

$$\widehat{MFP}^{c}_{HECO} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times \overline{trend\ Outputs_{HECO}}$$

$$- (\hat{\beta}_3 \times \overline{trend\ Other_{1,HECO}} + \hat{\beta}_4 \times \overline{trend\ Other_{2,HECO}}) - \hat{\beta}_T.^{8} \qquad [10]$$

Here $\widehat{MFP}_{HECO}$ is the projected annual MFP growth trend (average annual growth rate) for HECO during the final four years of its new plan. The variable $\overline{trend\ Outputs_{HECO}}$ is the expected growth trend in HECO's output index. $\overline{trend\ Other_{l,HECO}}$ is the expected growth trend for HECO in each external business condition l that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit*., were the first to use econometric research and a formula like [9] to decompose MFP growth. The method was also used several times in California proceedings.[9] In work for the Ontario Energy Board, PEG used this method in an Ontario gas PBR proceeding to project the MFP trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[10] These projections were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

MFP growth projections have several advantages in the design of an X factor for HECO. They are useful for ascertaining the reasonableness of an X factor which is based on more

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[8] Here is a more general formula.

$$\Delta\widehat{MFP}^{c}_{HECO} = (1 - \Sigma_i \hat{\beta}_i) \cdot E(growth\ Outputs^{c}_{HECO}) - \Sigma_l \hat{\beta}_l \cdot E(growth\ \overline{Others_{l,HECO}}) - \hat{\beta}_T$$

Here $\hat{\beta}_i$ is the econometric parameter estimate for each output variable i while $\hat{\beta}_l$ is the parameter estimate for each other business condition l that is included in the model.

[9] See, for example, California Public Utilities Commission A.98-01-014.

[10] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol.8, Issue 4, December 2009.

conventional industry cost trend research. Moreover, the projection can pertain to the specific costs that the ARA index will address. This sheds light on the need for an MPIR adjustment to the X factor. Despite being customized to HECO's business conditions, the use of these projections would not weaken the Company's cost containment incentives since they reflect only the cost impact of external business conditions.

3.2 VIEU Productivity Drivers

The usefulness of MFP growth projections depends on the sophistication with which the drivers of MFP growth are modelled. In the case of VIEUs the relevant drivers of MFP growth have in recent years included the following:

output growth

changes in various other business conditions

- need for replacement capex (aka "repex")
- need to reduce environmental costs (e.g., due to a renewable performance standard) by
  - adding pollution controls for fossil-fueled generators
  - extending the transmission system to remote renewable resources (e.g., wind and solar)
  - increasing generation from renewable resources
  - making other system improvements to accommodate renewables
- need for smart grid capabilities [e.g., automated metering infrastructure ("AMI")]
- reliability and resiliency standards
- need for better bulk power markets (e.g., fewer load pockets that are vulnerable to price spikes)
- changes in the technologies for providing utility products
- number of gas customers

Some of these conditions affect the MFP growth of utilities more than others. For example, MFP growth is especially sensitive to repex for several reasons.

- Utility technology is capital-intensive.
- Highly depreciated assets valued in *historical* dollars are replaced with assets which are valued in *current* dollars, are designed to last for decades, and must conform to the latest performance standards (e.g., National Electric Safety Code 2017). These standards typically exceed any that were previously applicable and may incorporate new technologies.
- Under the cost of service accounting traditionally used in ratemaking, the cost impact of repex is magnified by the fact that assets are valued in historical dollars.
- There is typically no counterbalancing growth in measured output.

Other kinds of capex (e.g., for better metering and pollution controls) may also improve system capabilities in ways that are not captured by the output index.

3.3 New Econometric Cost Model

Guided by the above analysis, PEG developed a new econometric model of VIEU cost. This model differed from that used in our research for the August report chiefly in including additional business condition variables that could sharpen analysis of recent MFP trends and provide the basis for good MFP growth projections. We added variables to capture the cost impact of recent generation capacity additions and system age challenges.[11]

Age Variable

An important focus of our new research has been the development of an appropriate age variable for the econometric work. To the extent that assets near and then exceed their average service lives ("ASLs"), cost tends to rise due to a greater need for repex. If the need for repex increases, intuition suggests that MFP growth will slow.

Standardized data on the age of assets are, unfortunately, not readily available for a large sample of U.S. electric utilities. However, extensive data are available on the value of gross additions to various kinds of electric utility plant in numerous prior years. We have used

[11] We excluded one variable from the previous model: the share of generation capacity fueled by coal or heavy oil.

these data to develop a repex requirement indicator ("RRI") for transmission and distribution ("T&D") assets.[12] This variable indicates how the need for T&D repex varies between utilities and changes over time.

The need for repex is modeled as a 13-year moving sum of the quantity of gross plant additions made ASL years ago, six years further into the past, and five years forward into the future.[13] For each asset j in year t-s let $VKA_{j,t-s}$ be the *value* of gross plant additions, $XKA_{j,t-s}$ be the *quantity* of plant additions, and $WKA_{j,t-s}$ be the value of the corresponding regional Handy-Whitman indexes ("HWIs") of electric utility construction costs. The repex requirements index for asset class j in year t ("$RRI_{j,t}$") then has the formula

$$RRI_{j,t} = \sum_{s=ASL-6}^{ASL+6} XKA_{j,t-s}$$

$$= \sum_{s=ASL-6}^{ASL+6} VKA_{j,t-s} / WKA_{j,t-s}$$

We calculated RRIs for transmission and distribution and then calculated the summary RRI for T&D by summing the separate T&D RRIs.

$$RRI_{TD,t} = RRI_{T,t} + RRI_{D,t}.$$

The assumed T&D ASLs were 54 years for HECO and 51 years for the mainland VIEUs.[14][15] Good data are available for HECO's T&D plant additions back to 1959, and the earliest year for which

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[12] Such an indicator is more problematic to construct for generation because aging generating plants may not be replaced, and replacements that are made may have a markedly different character (e.g., coal-fired capacity might be replaced with a mix of gas-fired and wind-powered capacity).

[13] This particular formulation had the strongest statistical support.

[14] For both the U.S. and HECO, the ASL was calculated as a weighted average of the lives of different types of T&D plant and equipment. In both cases the service lives from Hawaii PUC order number 35606 were used. The shares of gross plant by FERC account in total T&D gross plant were used as weights. The calculations for HECO and the mainland utilities differed in that sample average weights were used to calculate an ASL of 51 years. When the analogous HECO weights were used an ASL of 54 years was obtained.

[15] We use consolidated ASLs for T&D because if we used separate ASLs we would have to further limit the sample period for the econometric work because the ASL for transmission is higher than that for distribution.

we need a value for RRI in our MFP growth projections is 2020. We could therefore only consider plant additions 6 years before the average service life since 2020 - 54 - 1 - 6 = 1959. We expect that cost will be higher the higher is the value of the RRI.

Capacity Addition Variable

We also calculated a variable, MWadd, that was a moving sum of the megawatts ("MW") of generation capacity additions in the last ten years.

$$MWadd_t = \sum_{s=10} MW_{t-s}.$$

We expect that cost will be higher the higher is the value of MWadd.

Model Estimation

To estimate the parameters of the new VIEU cost model we used data from the same 45 utilities which we considered in our research for the August report. The 2006-17 sample period used to estimate this model was shorter than that for the August model due to limitations on the available age data. Data on T&D gross plant additions are only available back to 1948 for the 45 mainland utilities. The year 2006 is therefore the first for which the age variable in the model can be calculated because 1948 + 6 + 1+ 51 = 2006. This research required us to process plant addition data for the sampled utilities and predecessor companies from 1948 to 1964. [16]

Details of the new cost model are reported in Table 4. Please note the following key results.

[16] We had previously gathered these data only back to 1964.

Table 4

New Econometric Model of Total Base Rate Input Cost

Explanatory Variable	Parameter Estimate	T-Statistic	P-Value
Number of Customers	0.307	11.744 ***	0.000
Fossil Steam and Other Generation Volume	0.120	8.623 ***	0.000
Mid-Year Generation Capacity	0.194	8.156 ***	0.000
Mid-Year Transmission Line Miles	0.076	8.833 ***	0.000
Ratcheted Maximum Peak Demand	0.098	3.144 **	0.000
Percentage of Capacity Scrubbed	0.155	12.696 ***	0.000
Transmission and Distribution Plant Additions between 7 Years Younger and 6 Years Older than Average Service Life	0.104	6.378 ***	0.000
Percentage of Customers without AMI	-0.035	-1.777 *	0.076
Number of Gas Customers	-0.041	-3.837 ***	0.000
MW of Generation Capacity Added in Previous 10 Years	0.046	3.885 ***	0.000
Constant	20.273	1014.085 ***	0.000
Trend	0.002	2.185 **	0.029
Adjusted R-squared	0.962		
Sample Period	2006-2017		
Number of Observations	540		

*Estimate is significant at the 75% confidence level
**Estimate is significant at the 95% confidence level
***Estimate is significant at the 99.9% confidence level

- All five of the scale variables from the model in our August report still have statistically significant elasticity estimates. However, their relative magnitudes changed. Most notably, the generation volume has a higher estimate while customers and generation capacity have lower estimates.
- The share of generation capacity which was scrubbed had a positive and statistically significant cost impact. Our research found that a 1 % increase in the scrubbing share typically raised cost by about 0.16%. This means that an increase in the share of generation scrubbed tended to slow MFP growth.
- The number of gas customers served had a negative and statistically significant (though small) impact on cost. A 1% increase in gas customers typically reduced cost by about 0.04%. This means that gas customer growth accelerated electric MFP growth.
- T&D system age had a positive and highly significant impact on cost. A 1% increase in the RRI typically increased cost by about 0.10%. This means that an increase in RRI_{TD} tended to slow MFP growth.
- Recent generation capacity additions also had a statistically significant positive cost impact. A 1% increase in recent capacity additions typically raised cost by about 0.05%. This means that growth in recent capacity additions tended to slow MFP growth.
- The share of customers who do not have AMI had a statistically significant negative cost impact. A 1% decline in this share typically raised total cost by about 0.04%. This means that growth in AMI tended to slow MFP growth.
- The parameter estimate for the trend variable was also positive and statistically significant. It indicates that the cost of sampled utilities tended to *rise* by 0.25% annually for reasons that are not explained by the business conditions included in the model.

We also tried to consider the cost impact of transmission line growth. The variable we developed for this business condition did not have statistically significant parameter estimate and was excluded from the model.

3.4 HECO Output Growth

We explained in Section 2.1 above that, since the ARA indexes for the HECO Companies will not have explicit scale escalators, the expected growth in their scale is a valid concern in the choice of their X factors. Table 5 presents the latest forecasts of growth in the five outputs for each HECO Company.[17] These forecasts are tailored to the costs that will likely be addressed by the ARA index. Accordingly, we hold growth in generation capacity and transmission line miles at zero because the cost impact of any growth in these two scale variables would likely be addressed by cost trackers.

Forecasts of the other three output variables were obtained from the Company. We combined these with the econometric cost elasticity estimates for these variables which we reported in August to create forecasts of scale index growth for each company. Results are reported in Table 5. It can be seen that the forecasted annual growth trends in these "restricted" scale indexes are 0.27% for HECO, 0.40% for HELCO, and 0.24% for MECO.

[17] The impact of Covid-19 on output growth was not considered.

Table 5

Forecasted Growth in HECO Company Outputs

Output Variables	Ratcheted Maximum Peak Demand [a]	Generation Capacity [b]	Generation Volume [c]	Customers [d]	Transmission Line Miles [e]	**Elasticity-weighted Scale Index (all variables)**	**Elasticity-weighted Scale Index (a, c and d only)**
Estimated Cost Elasticities[1]	0.17	0.21	0.07	0.37	0.09		
Elasticity Shares[2]	0.19	0.23	0.08	0.41	0.09		
Years			**HECO**				
2020	1,327.00	1,288.70	6,774,948.64	307,962.00	778.25**	1.000	1.000
2021	1,327.00	1,288.70	6,756,161.00	309,587.00	778.25	1.001	1.002
2022	1,327.00	1,288.70	6,810,143.46	311,210.00	778.25	1.004	1.005
2023	1,327.00	1,288.70	6,884,144.00	312,833.00	778.25	1.007	1.008
2024	1,327.00	1,288.70	6,963,418.12	314,460.00	778.25	1.010	1.011
AAGR[3]	**0.00%**	**0.00%**	**0.69%**	**0.52%**	**0.00%**	**0.26%**	**0.27%**
			HELCO				
2020	191.00	182.00	1,117,849.02	86,987.00	603.48*	1.000	1.000
2021	190.60	182.00	1,108,572.21	87,650.00	603.48	1.058	1.002
2022	192.20	182.00	1,113,842.95	88,353.00	603.48	1.064	1.007
2023	192.50	182.00	1,118,378.14	89,064.00	603.48	1.068	1.011
2024	193.70	182.00	1,123,887.73	89,764.00	603.48	1.073	1.016
AAGR[3]	**0.35%**	**0.00%**	**0.13%**	**0.79%**	**0.00%**	**1.77%**	**0.40%**
			MECO				
2020	217.30	268.50	1,132,358.22	73,131.00	258.35*	1.000	1.000
2021	217.30	256.53	1,114,367.97	73,771.00	258.35	0.992	1.002
2022	217.30	256.53	1,099,919.18	74,258.00	258.35	0.993	1.004
2023	217.30	256.53	1,098,178.85	74,770.00	258.35	0.996	1.007
2024	217.30	232.60	1,102,900.01	75,286.00	258.35	0.977	1.010
AAGR[3]	**0.00%**	**0.00%**	**-0.66%**	**0.73%**	**0.00%**	**-0.59%**	**0.24%**

**2019 is the last value available

[1] Elasticity shares drawn from Table 7 of PEG's August report.

[2] Elasticity estimates drawn from Table 6 of PEG's August report.

[3] AAGR =average annual (logarithmic) growth rate

3.5 HECO MFP Projections

Econometric MFP growth projections for HECO for the four indexing years of the MRP can be found in Table 6. These projections are also based on the econometric parameter estimates from our new cost model as well as on Company forecasts of changes in outputs and other cost model business conditions. Analogous projections cannot be calculated for HELCO or MECO because we lack analogous data on the age of their T&D systems. These projections are specific to the costs that we expect to be addressed by the ARA.

Table 6

Econometric MFP Projections for HECO

	Incremental Scale Economies				Impact of Other External Business Conditions																Trend Variable Parameter Estimate	Projected MFP Growth Rate
	Sum of Estimated Output Elasticities		Forecasted Scale Index Growth	Incremental Scale Economies	Share of Generation Capacity Scrubbed			Share of Customers without AMI			Percentage Growth in Generation Capacity in Last 10 Years (unweighted)			Transmission and Distribution Plant Additions 7 Years Younger to 6 Years Older than ASL[3]			Number of Gas Customers				
					Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_1$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_2$	Estimated Cost Elasticity[1]	Growth Rate	$Product_3$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_4$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_5$		
	[A]	[B=1-A]	[C]	[D=B*C]	ε_1	GR_1	ε_1*GR_1	ε_2	GR_2	ε_2*GR_2	ε_3	GR_3	ε_3*GR_3	ε_4	GR_4	ε_4*GR_4	ε_5	GR_5	ε_5*GR_5	J	$D - \sum\varepsilon*GR - J$
Years											**HECO**										
2021	0.794	0.21	0.13%	0.03%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	4.44%	0.46%	-4.09%	0.00%	0.00%	0.25%	-0.68%
2022	0.794	0.21	0.26%	0.05%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	7.67%	0.80%	-4.09%	0.00%	0.00%	0.25%	-0.99%
2023	0.794	0.21	0.29%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	3.84%	0.40%	-4.09%	0.00%	0.00%	0.25%	-0.59%
2024	0.794	0.21	0.30%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	0.73%	0.08%	-4.09%	0.00%	0.00%	0.25%	-0.26%
Averages			**0.24%**	**0.05%**	**15.53%**	**0.00%**	**0.00%**	**-3.54%**	**0.00%**	**0.00%**	**4.55%**	**0.00%**	**0.00%**	**10.37%**	**4.17%**	**0.43%**	**-4.09%**	**0.00%**	**0.00%**	**0.25%**	**-0.63%**

[1] Elasticities drawn from PEG econometric model.
[2] Growth rates are calculated logarthmically.
[3] ASL = Average service life of utility assets

- HECO doesn't anticipate increasing its scrubbing generation capacity in the next five years and if it did the costs would likely be addressed by the MPIR tracker.
- HECO has no gas customers and so the cost of its electric services will not be lowered by growth in the number of these customers.
- Costs of the AMI buildout will be addressed by the MPIR.
- The cost of any growth in transmission line miles and generation capacity would likely be addressed by the MPIR.
- The Company must, however, contend with a rising value for the T&D repex requirement indicator.

Table 6 indicates that, when these business conditions are taken into account, the MFP growth of HECO is predicted to average a 0.63% annual decline in the 2021-24 period. This compares to the -0.45% MFP trend of the sampled VIEUs which we have calculated over the fifteen year 2003-2017 sample period using the Kahn method.

4. New Index Research

We have also calculated X using the input price and productivity differentials that are traditionally used in other jurisdictions such as Massachusetts. These calculations used the cost of service ("COS") approach to measuring capital cost which we discussed on page 19 of our August report. The COS approach is mathematically complicated but designed to resemble the way that capital cost is calculated under cost of service regulation while still preserving the ability to decompose capital cost into a price and a quantity index. Historical plant valuations and straight-line depreciation are assumed. This approach greatly reduces the volatility of the capital price. With alternative capital cost specifications (e.g., one hoss shay), capital price volatility has led to controversy over input price differentials in several proceedings, including the recent National Grid proceeding in Massachusetts.

Results of this exercise can be found in Table 7. These results use the output index from our August report because HECO has chosen to base its X factor proposal on this research.[18] Over the 15-year 2003-2017 sample period, it can be seen that the indicated X factor is the same -1.32% that was produced by the corrected Kahn method calculations. This was the sum of a -1.16% productivity differential and a -0.17% input price differential. The substantially negative productivity differential reflects the fact that GDPPI inflation was slowed during the sample period by the 0.70% annual growth trend of the economy.[19] The MFP growth of the sampled VIEUs averaged -0.46%. The consistency of these results with our Kahn method calculations is notable.

[18] The cost model featured in the August report was also estimated with data for a longer sample period.

[19] The -0.17% input price differential is far below those approved in the two recent Massachusetts PBR proceedings. This reflects our use of the COS capital cost specification.

Table 7

X Factor Calculations Using Input Price and Productivity Differentials

Year	GDPPI	Input Price Index - Economy	Industry Input Price Growth	Input Price Differential	MFP Industry	MFP Economy	Productivity Differential	X-Factor
	A	B = A + F	C	D = B - C	E	F	G = E - F	H = D + G
1997	1.70%	2.52%	3.72%	-1.20%	2.52%	0.82%	1.71%	0.51%
1998	1.08%	2.56%	3.98%	-1.42%	2.38%	1.48%	0.90%	-0.53%
1999	1.42%	3.47%	0.61%	2.87%	0.99%	2.05%	-1.06%	1.81%
2000	2.25%	3.77%	5.71%	-1.94%	0.73%	1.52%	-0.79%	-2.73%
2001	2.26%	2.85%	2.04%	0.81%	0.04%	0.59%	-0.55%	0.26%
2002	1.52%	3.55%	1.98%	1.57%	0.93%	2.03%	-1.10%	0.46%
2003	1.98%	4.35%	2.10%	2.26%	0.86%	2.37%	-1.52%	0.74%
2004	2.71%	4.90%	2.33%	2.57%	0.05%	2.19%	-2.15%	0.42%
2005	3.17%	4.69%	2.30%	2.39%	1.66%	1.52%	0.15%	2.54%
2006	3.02%	3.50%	2.89%	0.61%	-0.23%	0.48%	-0.71%	-0.10%
2007	2.63%	3.18%	3.08%	0.10%	-0.58%	0.55%	-1.12%	-1.03%
2008	1.91%	0.73%	4.00%	-3.28%	-0.59%	-1.19%	0.60%	-2.68%
2009	0.78%	1.03%	2.99%	-1.95%	-2.09%	0.25%	-2.34%	-4.30%
2010	1.22%	3.81%	3.01%	0.80%	-2.29%	2.59%	-4.88%	-4.08%
2011	2.04%	1.87%	2.70%	-0.83%	0.44%	-0.18%	0.61%	-0.22%
2012	1.82%	2.51%	2.41%	0.10%	-0.32%	0.69%	-1.01%	-0.92%
2013	1.60%	1.64%	2.42%	-0.77%	-0.07%	0.04%	-0.11%	-0.88%
2014	1.78%	2.27%	2.46%	-0.19%	-2.11%	0.49%	-2.60%	-2.79%
2015	1.06%	1.92%	3.41%	-1.50%	-0.63%	0.86%	-1.49%	-2.99%
2016	1.31%	0.70%	1.21%	-0.51%	-1.34%	-0.61%	-0.73%	-1.24%
2017	0.89%	1.29%	3.58%	-2.29%	0.34%	0.40%	-0.05%	-2.35%

Average Annual Growth Rates

1997-2017	**1.82%**	**2.72%**	**2.81%**	**-0.09%**	**0.03%**	**0.90%**	**-0.87%**	**-0.96%**
2003-2017	**1.86%**	**2.56%**	**2.73%**	**-0.17%**	**-0.46%**	**0.70%**	**-1.16%**	**-1.32%**
2008-2017	**1.44%**	**1.78%**	**2.82%**	**-1.04%**	**-0.87%**	**0.33%**	**-1.20%**	**-2.24%**

5. Comparative Age Data

Our new econometric work suggests that the age of T&D assets is an important consideration in choosing X factors for the HECO companies. This raises the question of how old are HECO's T&D assets. Our recent research has included some statistical age comparisons.

We first calculated the accumulated depreciation ratios ("ADRs") for HECO and the sampled VIEUs. An ADR is the ratio of accumulated depreciation expenses to gross plant value. This is a measure of the *typical* age of utility assets. A high value for the ADR indicates higher typical age.

Table 8 compares the 2019 ADR for HECO to the 2017 ADRs for the VIEUs in our sample. It can be seen that HECO had the highest T&D ADR of all of VIEUs in our sample. Its distribution ADR ranked 1st and its transmission ADR ranked 6th. Distribution generally gets greater weight in a consolidated T&D ADR computation because Dx assets are more valuable.

One disadvantage of ADRs as measures of repex requirements is that they don't focus on the importance of assets that may imminently need replacement. We accordingly calculated, for the year 2017, the (inflation-adjusted) quantities of T&D assets that HECO added in the last 58 years and then considered what share of these quantities were added from 46 to 58 years ago. Results of this exercise are presented in Table 9. It can be seen that HECO had the fourteenth highest share out of 46 VIEUs considered.

Table 8

Accumulated Depreciation Ratios of HECO and Sampled VIEUs (2017)

	End of Year Gross Value of Plant			Accumulated Depreciation			Accumulated Depreciation to Gross Plant Value Ratios		
	Distribution [A]	Transmission [B]	Transmission & Distribution [C=A+B]	Distribution [D]	Transmission [E]	Transmission & Distribution [F=D+E]	Distribution [D/A]	Transmission [E/B]	Transmission & Distribution [F/C]
Hawaiian Electric*	**1,997,726,421**	**1,140,149,811**	**3,137,876,232**	**1,006,153,763**	**418,944,910**	**1,425,098,673**	**50.36%**	**36.74%**	**45.42%**
Union Electric Company	5,765,762,048	1,201,003,904	6,966,765,952	2,706,232,064	347,318,336	3,053,550,400	46.94%	28.92%	43.83%
Duke Energy Progress, Inc. (Carolina Power & Light)	6,236,201,472	2,619,581,696	8,855,783,168	3,005,977,600	798,253,120	3,804,230,720	48.20%	30.47%	42.96%
Tucson Electric Power Company	1,632,402,816	1,001,445,568	2,633,848,384	619,790,272	430,419,296	1,050,209,568	37.97%	42.98%	39.87%
Duke Energy Carolinas, LLC	11,345,729,536	3,874,750,720	15,220,480,256	4,657,540,096	1,403,966,080	6,061,506,176	41.05%	36.23%	39.82%
Mississippi Power Company	945,156,544	673,983,552	1,619,140,096	398,758,944	242,824,864	641,583,808	42.19%	36.03%	39.62%
Empire District Electric Company	949,112,320	359,691,936	1,308,804,256	419,838,560	94,678,048	514,516,608	44.23%	26.32%	39.31%
Duke Energy Indiana, Inc. (Public Service Company of Indiana)	3,052,046,592	1,589,453,312	4,641,499,904	1,237,162,752	508,933,504	1,746,096,256	40.54%	32.02%	37.62%
ALLETE (Minnesota Power)	586,984,640	775,409,920	1,362,394,560	270,588,768	238,204,912	508,793,680	46.10%	30.72%	37.35%
Kentucky Utilities Company	1,803,849,216	924,691,648	2,728,540,864	670,817,408	337,138,272	1,007,955,680	37.19%	36.46%	36.94%
Louisville Gas and Electric Company	1,370,549,888	432,829,792	1,803,379,680	506,337,760	158,104,576	664,442,336	36.94%	36.53%	36.84%
Southwestern Electric Power Company	694,909,824	487,736,736	1,182,646,560	295,418,048	133,802,064	429,220,112	42.51%	27.43%	36.29%
Kansas City Power & Light Company	2,388,798,208	496,676,000	2,885,474,208	826,347,200	204,671,392	1,031,018,592	34.59%	41.21%	35.73%
MDU Resources Group, Inc. (Montana-Dakota Utilities)	415,542,624	296,941,440	712,484,064	148,903,504	105,443,352	254,346,856	35.83%	35.51%	35.70%
Puget Sound Energy, Inc.	3,817,603,840	1,536,971,648	5,354,575,488	1,420,269,824	489,194,240	1,909,464,064	37.20%	31.83%	35.66%
Tampa Electric Company	2,437,444,096	859,088,576	3,296,532,672	983,985,664	191,193,024	1,175,178,688	40.37%	22.26%	35.65%
El Paso Electric Company	1,170,990,336	491,438,336	1,662,428,672	361,185,760	224,289,712	585,475,472	30.84%	45.64%	35.22%
MidAmerican Energy Company	2,856,761,088	1,833,480,576	4,690,241,664	1,141,918,336	496,162,144	1,638,080,480	39.97%	27.06%	34.93%
Florida Power & Light Company	15,796,473,856	5,395,656,704	21,192,130,560	5,499,323,904	1,870,325,760	7,369,649,664	34.81%	34.66%	34.78%
Monongahela Power Company	1,791,305,088	460,648,032	2,251,953,120	591,899,968	186,834,672	778,734,640	33.04%	40.56%	34.58%
Idaho Power Co.	1,710,126,208	1,163,240,448	2,873,366,656	628,829,056	364,308,768	993,137,824	36.77%	31.32%	34.56%
Alabama Power Company	7,032,719,360	4,119,101,184	11,151,820,544	2,548,985,600	1,291,912,576	3,840,898,176	36.24%	31.36%	34.44%
PacifiCorp	6,781,903,360	6,222,285,824	13,004,189,184	2,783,524,608	1,679,410,048	4,462,934,656	41.04%	26.99%	34.32%
Otter Tail Power Company	482,845,888	500,284,992	983,130,880	210,361,952	120,734,336	331,096,288	43.57%	24.13%	33.68%
Cleco Power LLC	1,455,913,600	722,335,680	2,178,249,280	492,741,280	233,670,608	726,411,888	33.84%	32.35%	33.35%
Entergy New Orleans, Inc. (New Orleans Public Service)	674,195,712	153,025,920	827,221,632	205,169,056	68,878,768	274,047,824	30.43%	45.01%	33.13%
Southwestern Public Service Company	2,096,724,608	1,679,310,720	3,776,035,328	717,641,344	501,945,376	1,219,586,720	34.23%	29.89%	32.30%
Northern States Power Company - MN	4,001,157,888	3,592,396,544	7,593,554,432	1,585,108,352	854,348,608	2,439,456,960	39.62%	23.78%	32.13%
Nevada Power Company	3,310,183,424	1,409,618,176	4,719,801,600	1,123,066,496	388,412,480	1,511,478,976	33.93%	27.55%	32.02%
Black Hills Power, Inc.	376,277,440	184,727,232	561,004,672	133,804,896	43,694,320	177,499,216	35.56%	23.65%	31.64%
Indiana Michigan Power Company	2,069,063,808	1,503,669,760	3,572,733,568	608,012,864	515,733,696	1,123,746,560	29.39%	34.30%	31.45%
Gulf Power Company	1,282,276,608	719,683,072	2,001,959,680	485,904,320	141,359,984	627,264,304	37.89%	19.64%	31.33%
Avista Corporation (Washington Water Power)	1,643,539,200	722,397,568	2,365,936,768	527,773,760	211,556,288	739,330,048	32.11%	29.29%	31.25%
Duke Energy Florida, Inc. (Florida Power)	5,479,825,408	3,105,263,104	8,585,088,512	1,969,014,656	683,543,872	2,652,558,528	35.93%	22.01%	30.90%
Virginia Electric and Power Company	11,097,772,032	8,301,881,856	19,399,653,888	4,391,818,240	1,446,902,912	5,838,721,152	39.57%	17.43%	30.10%
Appalachian Power Company	3,761,628,928	3,018,312,192	6,779,941,120	1,273,050,880	716,358,528	1,989,409,408	33.84%	23.73%	29.34%
Oklahoma Gas and Electric Company	4,050,774,016	2,621,320,704	6,672,094,720	1,359,161,856	580,920,256	1,940,082,112	33.55%	22.16%	29.08%
Entergy Arkansas, Inc. (Arkansas Power & Light)	3,354,571,264	2,196,105,472	5,550,676,736	1,099,171,840	495,532,448	1,594,704,288	32.77%	22.56%	28.73%
South Carolina Electric & Gas Co.	3,286,827,776	1,603,540,352	4,890,368,128	1,029,790,144	362,089,760	1,391,879,904	31.33%	22.58%	28.46%
Arizona Public Service Company	6,024,269,312	2,831,375,104	8,855,644,416	1,681,837,312	801,763,456	2,483,600,768	27.92%	28.32%	28.05%
Kansas Gas and Electric Company	1,135,290,624	991,892,032	2,127,182,656	313,376,512	269,193,088	582,569,600	27.60%	27.14%	27.39%
Entergy Mississippi, Inc. (Mississippi Power & Light)	1,885,919,360	1,257,741,952	3,143,661,312	473,904,960	358,392,800	832,297,760	25.13%	28.49%	26.48%
Public Service Company of Colorado	4,809,704,960	2,133,315,200	6,943,020,160	1,377,868,288	459,624,608	1,837,492,896	28.65%	21.55%	26.47%
Westar Energy (Western Resources or Kansas Power & Light)	1,366,391,808	1,299,441,152	2,665,832,960	357,783,392	316,321,696	674,105,088	26.18%	24.34%	25.29%
Public Service Company of Oklahoma	2,444,828,672	858,822,464	3,303,651,136	587,879,872	204,435,440	792,315,312	24.05%	23.80%	23.98%
Southwestern Public Service Company	1,297,259,392	2,678,015,232	3,975,274,624	356,124,224	404,067,552	760,191,776	27.45%	15.09%	19.12%
Averages	**3,260,159,589**	**1,783,494,214**	**5,043,653,803**	**1,197,612,086**	**486,865,534**	**1,684,477,620**	**36.08%**	**29.52%**	**33.42%**

46 Companies considered
*Values for Hawaiian Electric are preliminary 2019 data for the Company's Annual PUC Report.

Table 9

Estimated Prevalence of Old T&D Plant (2017)

(Sorted Oldest to Youngest)

	Ratio of 46-58 Year-Old Plant Additions to Total Plant Additions (adjusted for inflation)	Rank
Entergy New Orleans	44.4%	1
Union Electric	36.6%	2
Indiana Michigan Power	35.2%	3
Kansas City Power & Light	32.3%	4
MDU Resources Group	31.6%	5
Otter Tail	30.5%	6
Kentucky Utilities	27.6%	7
Mississippi Power	27.5%	8
Entergy Arkansas	25.4%	9
Monongahela Power	25.2%	10
Louisville Gas and Electric	25.0%	11
Southwestern Public Service	24.4%	12
Northern States Power - MN	24.4%	13
HECO	24.3%	14
Kansas Gas and Electric	24.2%	15
Puget Sound Energy	23.8%	16
Public Service Company of Oklahoma	23.8%	17
MidAmerican Energy	23.7%	18
ALLETE (Minnesota Power)	23.7%	19
Appalachian Power	23.6%	20
Duke Energy Indiana	23.6%	21
Duke Energy Carolinas	22.8%	22
Tampa Electric	22.2%	23
Idaho Power	22.0%	24
Entergy Mississippi	21.9%	25
Southern Indiana Gas and Electric	21.7%	26
Westar Energy (KPL)	21.5%	27
Oklahoma Gas and Electric	21.0%	28
Southwestern Electric Power	20.4%	29
Cleco Power	20.3%	30
Public Service Company of Colorado	19.6%	31
Gulf Power	19.5%	32
Florida Power	19.0%	33
Virginia Electric and Power	18.9%	34
PacifiCorp	17.0%	35
Avista	16.7%	36
South Carolina Electric & Gas	16.7%	37
Carolina Power & Light	16.5%	38
Empire District Electric	16.2%	39
Florida Power & Light	16.2%	40
Black Hills Power	16.2%	41
Arizona Public Service	16.1%	42
El Paso Electric	15.5%	43
Alabama Power	15.5%	44
Tucson Electric Power	14.8%	45
Nevada Power	7.6%	46
Average	**22.5%**	
Median	**22.1%**	

The importance of T&D system age is amplified for HECO because T&D assets loom especially large in the Company's cost structure. This reflects in large measure the sizable share of the Company's power supplies that are purchased rather than generated. Table 10 compares HECO's 2019 shares of T&D in both its gross and net plant value to 2017 full sample norms. It can be seen HECO's shares are unusually large.

Table 10

How the Composition of HECO's Plant Compares to 2017 Sample Norms

	Percent of Plant by Type of Plant		
	HECO*	**Sample**	**HECO vs Sample**
Percent of Plant by Type of Plant			
Gross Plant			
Total Plant			
Generation	26.3%	45.8%	-19.5%
Transmission	23.7%	17.8%	5.9%
Distribution	41.6%	31.0%	10.5%
Other	8.4%	5.4%	3.1%
Net Plant			
Total Plant			
Generation	29.7%	45.6%	-15.9%
Transmission	26.0%	19.6%	6.4%
Distribution	35.7%	28.8%	7.0%
Other	5.0%	4.0%	0.9%

*HECO values are preliminary for 2019.

6. MPIR Adjustment

6.1 Combining an ARA Index with Capex Trackers is Warranted for HECO

Productivity growth drivers vary between utilities and, over time, for the same utility. An X factor based on industry cost (e.g., input price and productivity) trends is therefore not always compensatory for the subject utility during the term of an MRP. MRPs that have ARAs based on cost trends therefore often have some provision for supplemental capital revenue (e.g., Alberta, British Columbia, Ontario) if the need for such revenue can be substantiated. Cost trackers are commonly used for this purpose and also have other justifications.

The fairness of supplemental revenue provisions is magnified if the subject utility has either not previously operated under MRPs or has operated under such plans but the prior ARA index was under compensatory. On a net present value basis, *under* compensation in the early years of operation under MRPs will tend to outweigh any possible *over*compensation in future years. Hence, initial MRPs with under compensatory ARA formulas would, under these circumstances, tend to be unfair to the utility.

There are several reasons to believe that combining capex trackers for renewables-related and major plant additions with an ARA formula based on industry cost trends is justifiable for HECO. Some of these reasons are revisited below.

- HECO has been compelled to operate for several years with a *growth GDPPI – 0* "RAM Cap" formula and has underearned despite its capital cost trackers. This suggests that *growth GDPPI – 0* has been an under compensatory ARA formula for the costs that it addresses.
- Growing numbers of the Company's T&D assets are reaching replacement age so that high repex will be needed during the plan. This repex will materially slow MFP growth and will likely not be eligible for tracker treatment.
- Due chiefly to the large share of its power supplies which HECO purchases rather than self-generates, T&D cost looms unusually large in the total cost that will be addressed by HECO's ARA index.

- The ARA index will contain no scale escalator.
- With its unusually high and growing reliance on intermittent renewable resources, the Companies may face other special cost pressures that are beyond its control.
- The Commission and/or some intervenors may wish to weigh in on HECO's renewables-related and major plant additions in advance. Capex trackers provide that opportunity.

6.2 Any Need to Adjust the MRP for Potential Overcompensation due to the MPIR is Limited

Despite the need for a capex tracker, it is possible for the combination of such a tracker and an RCI based on industry cost trend research to overcompensate HECO for its cost challenges. The following considerations suggest that the need to adjust HECO's MRP for overcompensation is limited, however.

- The share of HECO's capex that is tracked will likely be limited by eligibility restrictions. In addition to general eligibility restrictions (e.g., capex must be major or renewables-related), overruns may be ineligible for tracking and a portion of otherwise-eligible capex may occasionally be marked down, as happened with the Schofield Barracks project. The great bulk of HECO's capex, including all or nearly all repex, has not been tracked in most years since the MPIR was established.
- The approved ARA formula has no explicit scale escalator.
- Even if no output growth was expected, the extent of any overcompensation is not near the -1.32% proposed value of the X factor that our Kahn method calculations suggest are warranted. We showed in Table 3 that the X factor is negative chiefly due to the inflation differential. This differential was -0.99% for the full 21-year 1997-2017 sample period that PEG considered. For the fifteen-year 2003-2017 period the inflation differential was -0.86%.
- We developed an MFP growth projection that was specific to the costs that will be addressed by the ARA formula. No growth was assumed in generation capacity,

scrubbing capacity, transmission line miles, or AMI. The 0.45% decline in MFP growth that is implicit in the Company's proposal is quite reasonable compared to our -0.63% MFP growth projection.

- Many approved MRPs that combine ARA indexes based on cost trend research with capital cost trackers have no provisions intended to reduce possible overcompensation that may result. Examples include the current MRPs for power distributors in Alberta, British Columbia, and Massachusetts.

7. Conclusions

Our new research for HECO has shed additional light on the appropriate X factors for its ARA formulas. Using established cost theory and econometric methods, we identified drivers of VIEU productivity growth and estimated their productivity impacts. The need for T&D repex was found to be an important driver of MFP growth of sampled VIEUs in recent years. Ancillary statistics that we computed show that HECO has an unusually old T&D system.

We developed an MFP growth projection for HECO during the four indexing years of the Company's prospective PBR plan (2021-2024). This is the typical MFP growth that might be expected given the Company's business conditions. Considerable effort was devoted to customizing this projection to the costs that will be addressed by the ARA. This in principle eliminates the need for an MPIR adjustment to the X factor. MFP growth is projected to average a 0.63% annual decline on average during these years. The Company has proposed an X factor that reflects a -0.45% MFP trend that is more favorable to customers. X should be substantially more negative than the MFP growth target because GDPPI will be used as the inflation measure in the ARA formula and the formula will not include a scale escalator.

The -0.45% MFP growth target that is implicit in HECO's X factor proposal understates the growth in the true cost efficiency of sampled utilities for reasons that include the following.

- Costs of environmental damage that result from VIEU operations were excluded from the calculations because these costs are difficult to estimate accurately and are irrelevant for ratemaking. During the sample period, capex for pollution controls, gas- and renewable-powered generation, and for T&D capacity needed to increase reliance on renewables slowed calculated MFP growth but reduced environmental costs.
- Costs of generation fuel were excluded from the calculations because these costs would be tracked in HECO's new MRPs. Investments in renewable-powered generation and T&D facilities needed to handle the resultant intermittent power flows slowed calculated MFP growth but also reduced use of generation fuels.

- Some distribution capex improved system reliability and resilience, and the output index does not reflect this either.

Thus, in accepting an X factor of -1.32% that reflects a -0.45% MFP growth trend, the Commission would not acquiesce in a poor MFP growth standard.

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Designing Revenue Adjustment Indexes for Hawaiian Electric Companies

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Table of Contents

Executive Summary

Hawaii's Public Utilities Commission recently issued the Phase 1 decision in its proceeding on a new performance-based regulation framework for the Hawaiian Electric Company ("HECO") and its utility affiliates. A multiyear rate plan ("MRP") will feature index-driven adjustments to allowed revenue. The revenue adjustment index formula will include an inflation factor, a predetermined productivity (aka "X") factor, and a consumer dividend.

Pacific Economics Group Research LLC personnel pioneered the use of input price, productivity, and other statistical cost research to design rate and revenue adjustment indexes for energy utilities. HECO has asked us to undertake research to aid development of revenue adjustment indexes. This is a report on our research to date.

X Factor

Theoretical Underpinnings

We discuss principles for the design of revenue adjustment indexes in Section 3 of our report. A key result is that, if the gross domestic product price index ("GDPPI") is the sole inflation measure, the X factor should reflect the industry productivity growth trend and an inflation differential. The inflation differential is the difference between the trends in the GDPPI and industry input prices. This matters because GDPPI growth has historically been slowed by the brisk growth in the productivity of the U.S. economy.

The productivity growth of a utility is influenced by many drivers that are beyond its control. For example, slow demand growth reduces opportunities to increase capacity utilization and realize incremental scale economies. An unusually large share of assets nearing retirement age can create an outsized need for capex. It is possible, then, for the expected productivity growth of a utility to differ from the industry trend during an MRP for reasons that are beyond its control.

Theoretical analysis also suggests that a revenue adjustment index should have a scale escalator that measures growth in the operating scale of the subject utility. For vertically integrated utilities such as the HECO Companies, it makes sense to consider multidimensional scale indexes that take a weighted average of growth in the scale of generation, transmission, and distributor services. If an MRP does not compensate a utility for growth in its operating scale, the expected growth in the scale of the utility is an implicit stretch factor.

Empirical Research

We gathered a sample of publicly available data on the operations of 45 U.S. vertically integrated electric utilities ("VIEUs") to calculate the X factor that would have been compensatory on average had these utilities been subject to revenue adjustment indexes featuring GDPPI as the inflation measure. The resultant "Kahn method" X factors reflect the appropriate inflation differential as well the base productivity trend but does not itemize them. We excluded from these calculations costs of nuclear and hydroelectric generation and certain other itemized costs that are not pertinent to the situation of the HECO Companies.

We found that the indicated Kahn X factor was **-1.04**% for the full 1997-2017 sample period. The X factor was even more negative for more recent sample periods, falling to **-1.41**% for the last fifteen years (2003-2017) and to **-2.35**% for the last 10 years (2008-2017). In these calculations, we found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. The rate base grew especially rapidly, and its growth tended to accelerate materially after 2006.

We also considered the appropriate inflation differential. For each VIEU in our sample we calculated a multifactor index of the growth in prices of pertinent base rate (non-energy) inputs. In these calculations, we used a capital price index designed to mimic the traditional cost of service treatment of capital used in utility ratemaking. The trend in this index depends on trends in electric utility construction costs and the rate of return on capital. We used the input price indexes to calculate the average inflation differential for the sampled companies. The growth trend in the industry input price indexes was found to be substantially more rapid on average than that of the GDPPI. Over the full 1997-2017 sample period, industry input price growth exceeded GDPPI growth each year by 0.99% on average. The inflation differential was similar over the last fifteen years of the sample but worsened to -1.38% over the last ten years of the sample, due chiefly to slower GDPPI inflation since the recession of 2008.

The difference between the Kahn X factor and the inflation differential is a rough estimate of the multifactor *productivity* growth trend of VIEUs. Over the full sample period, we found that productivity thus calculated declined by about 0.05% annually on average. Productivity averaged a 0.54% decline over the last fifteen years and a 0.97% decline over the last ten years.

The slowing productivity growth of VIEUs merits explanation. Slower demand growth has reduced the industry's ability to increase capacity utilization and realize new scale economies. Meanwhile, the industry has made sizable capital expenditures in order to install pollution controls, generate more power from renewable resources and cleaner-burning natural gas, and modernize the grid. Important improvements in utility performance such as reduced pollution are not captured by our productivity calculations.

Consumer Dividend

The consumer dividend term of a revenue adjustment index should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target for reasons that are within the company's control. This depends in part on how the performance incentives generated by the MRP compare to those in the regulatory systems of utilities in the cost trend studies that are used to set the X factor. It also depends on the utility's operating efficiency at the start of the plan. The productivity growth of the utility should be more rapid to the extent that its initial inefficiency is greater.

Precedents

In Section 4 of the report we consider precedents for rate and revenue adjustment indexes in North American MRPs. We find that base productivity trends and stretch factors approved by regulators have been falling. X factors are typically lower when a macroeconomic price index such as the GDPPI is the sole inflation measure in the formula. The average X factor in current U.S. rate and revenue adjustment indexes is **-1.27%**. The average stretch factor in current North American MRPs is **0.22%.** Negative X factors are also common in Australian and British MRPs for energy utilities.

Plans with rate or revenue adjustment indexes often provide supplemental revenue for utilities with high capex requirements. The mechanisms for providing supplemental capital revenue vary. Precedents in Alberta, British Columbia, and Ontario are discussed in the report.

Application to the HECO Companies

Some special considerations are pertinent in an application of our research results to the design of revenue adjustment indexes for the HECO Companies. These Companies will have trackers for the cost of major plant additions. However, major plant additions typically account for less than half of the Companies' total additions. There may be markdowns on the capex that is otherwise eligible for tracker treatment. Moreover, the revenue adjustment indexes will not include scale escalators. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes.

1. Introduction

Hawaii's Public Utilities Commission ("PUC" or "the Commission") recently issued the Phase 1 decision in its proceeding to develop a new performance-based regulation ("PBR") framework for the Hawaiian Electric Company ("HECO") and its utility affiliates.[1] A multiyear rate plan ("MRP") will feature index-driven adjustments to allowed revenue which the Commission calls annual revenue adjustments ("ARAs"). The ARA formula will include an inflation factor, a predetermined productivity (aka "X") factor, and a consumer dividend.

Pacific Economics Group Research LLC ("PEG") personnel pioneered the use of input price, productivity, and other statistical cost research to design rate and revenue adjustment indexes for energy utilities. We have led the field since the 1990s and have worked on previous HECO PBR initiatives. Work for diverse clients has given us a reputation for objectivity and commitment to sound research methods. HECO has asked us to undertake empirical research to aid development of its ARA indexes.

This is a report on our work to date. Section 2 provides some pertinent background information on the regulation of the HECO Companies. In Section 3 we discuss the logic of using statistical cost research to design revenue adjustment indexes. There follows in Section 4 a discussion of notable precedents. Our empirical research for the HECO Companies is discussed in Section 5. Some topics are discussed in greater detail in the Appendix.

[1] Hawaii PUC, Proceeding to Investigate Performance-Based Regulation (2018-0088), Decision and Order No. 36326, May 23, 2019.

2. Background

The Hawaii PUC's Phase 1 decision sketched the outline of a new PBR framework for HECO and its utility affiliates. Each Company will operate under an MRP that features a revenue adjustment index. Revenue requirements that are currently in effect or reset in pending rate cases will serve as the cast-off levels for these indexes. Revenue decoupling will continue, and performance metric systems will be expanded. The terms of these plans will be 5 years.

The index formula will include an inflation factor, an X factor, and a consumer dividend, but not a scale escalator. The Commission stated that the inflation factor would be linked to "a published inflation index" but did not choose the index. PUC Staff stated in their February 7th report that

> The inflation measure [in an MRP] is often a macroeconomic price index such as the Gross Domestic Product Price Index ("GDPPI"); however, custom indexes of utility input price inflation are sometimes used in ARM design. The appropriate inflation measure will be an important consideration of Phase 2.[2]

Regarding the productivity factor, Staff stated in the same report that

> The productivity, or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer utilities. Phase 2 will need to determine the appropriate value for X; however, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).[3]

Most of the Companies' existing cost trackers and pass through mechanisms will continue in their next generation MRPs unchanged. These mechanisms include the Energy Cost Recovery Clause ("ECRC"), the Purchased Power Adjustment Clause, trackers for pensions and other post-retirement benefit costs, the IRP/DSM surcharge, and costs related to Hawaii's third-party DSM administrator.[4] The ECRCs would retain the fossil fuel cost risk sharing mechanism which, for HECO, requires it to absorb 2% of fossil fuel cost variances relative to baseline prices that are reset annually, as adjusted for generator heat rates, up to a cap of $2.5 million.

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[2] Hawaii PUC, *Staff Proposal for Updated Performance-Based Regulations*, February 7, 2019, p. 26.

[3] *Ibid*., pp. 26-27.

[4] The IRP/DSM surcharge is also used to address variances of the variable costs of demand response programs from amounts reflected in base rates.

Supplemental funding for capex is provided through Major Project Interim Recovery ("MPIR") Adjustment Mechanisms and Renewable Energy Infrastructure Project ("REIP") surcharges. Decision and Order No. 36326 stated that the Commission may consider revisions to the MPIR Guidelines in Phase 2.

> The commission will preserve a mechanism for interim cost recovery for exceptional projects, to the extent that it may not be feasible to appropriately provide cost recovery for all such investments during the MRP exclusively through the ARA. At this time, the commission envisions that extraordinary relief for eligible projects will continue to be governed according to the MPIR Guidelines; however, the commission may consider revisions to the MPIR Guidelines in Phase 2, in order to remain consistent with the principles, goals, and outcomes of the PBR framework described herein, as well as the specific PBR Mechanisms under consideration.

[Decision and Order No. 36326 at 10, footnote excluded.]

MPIR trackers address costs of major capital expenditure ("capex") projects, net of any related benefits that can be quantified and realized by the Companies, if they aren't already offset in rates. Major projects must involve capital expenditures net of customer contributions in excess of $2.5 million and may include, but are not restricted to, those for renewable energy interconnection and generation, those that encourage or enable energy efficiency and clean energy choices, grid modernization, and smaller qualifying projects grouped into programs for review. Capital costs do not flow through the mechanism until the project is deemed used and useful.

MPIR applications must include a business case for the project. These mechanisms cap recovery at the lesser of forecasted or actual cost. The depreciated balance of capex in excess of project caps may be considered for inclusion in rate base during a subsequent rate case.

Ratemaking treatments of capex may have additional incentivizing provisions that are determined on a case by case basis. For the Schofield Generating Station project, a load-following bio-fueled diesel generating station located on an army base, only 90% of the allowed capital costs were addressed through the MPIR. The depreciated balance of capital costs in excess of 90% of the project cost cap will be addressed in a subsequent HECO rate case. The MPIR tracker for this project also addresses incremental O&M expenses offset by any O&M cost savings and reduced emission fees related to the reduced use of other peaking units.

The HECO Companies recently received approval of MPIR trackers to address capital costs related to Phase 1 of their Grid Modernization Project, including costs of advanced meters, a master data management system, and a telecommunications network.[5] In each case, costs are capped at the lesser of actual costs (in total or per meter installed) and forecasts.

Renewable Energy Infrastructure Program ("REIP") surcharges can expedite recovery of capex and other related costs incurred to accommodate renewables on a project by project basis. Projects that may be addressed by this mechanism include those needed to maintain current renewable energy resources and/or to encourage the connection of new third party renewable energy projects to any of the Companies' systems; projects that encourage development of renewable energy resources by increasing the system's ability to accept more renewable energy on the HECO Companies' systems; and projects that encourage renewable choices and/or otherwise enhance renewable energy choices for customers.[6] The REIP surcharge is limited to 100% of approved eligible project costs. The Companies can request recovery of the depreciated balance of any capex overruns in subsequent rate cases. Recovery through the REIP surcharge does not begin until the project is deemed used and useful. The surcharge has been used to address the costs of several projects including a demand response management system, wind implementation studies, and at least one wind interconnection.

The Commission's Phase 1 decision also included a Z-factor as part of the revenue adjustment index. While the details of the eligibility criteria for Z-factors will be addressed in Phase 2, the PUC clarified the difference between Z-factors and the MPIR.

> Parties should consider relief provided under the MPIR adjustment mechanism as distinct from potential relief under the "Z-Factor" component of the MRP indexed revenue formula. "Z-Factor" events are intended to address unforeseen events and are considered in determining the amount of allowed revenue in accordance with the ARA formula, whereas the MPIR Guidelines are used to prospectively seek relief for planned "eligible projects" in addition to revenue determined by the indexed revenue formula.[7]

The Commission has proposed changing the HECO Companies' current earnings sharing mechanisms ("ESMs"), which asymmetrically refund to customers 25-90% of all overearnings, to mechanisms that would share negative as well as positive earnings variances that are outside of a dead band. The PUC indicated that the ESM could address overearning and under earning differently. Details on the implementation of the ESM will be addressed in Phase 2, including the mechanism's impact on

[5] The HECO Companies will also be able to continue to keep meters replaced through the AMI project in rate base until they are fully depreciated.

[6] AMI was provided as an example of a project that could encourage renewable energy choices and/or enhance renewable energy choices for customers.

[7] Hawaii PUC (2019), *op. cit.*, p. 35.

the HECO Companies' incentives to contain cost. The Commission also expressed interest in considering off-ramp mechanisms as part of Phase 2. Details of potential off-ramps will be considered as part of Phase 2.

The Commission adopted Staff's proposal to prioritize 12 regulatory outcomes in the performance metric system. Regulatory outcomes may be addressed by one or more of the following: performance incentive mechanisms ("PIMs"), scorecards where performance is reported relative to targets, and reporting-only metrics. The existing set of PIMs that address some dimensions of reliability and customer service performance will be maintained, while the PUC intends to add 3-6 new PIMs for selected regulatory outcomes.[8] The PUC also endorsed the potential of shared savings mechanisms to address the Companies' incentive to prefer capital solutions.

The PUC also encouraged the Companies to work with stakeholders to develop a proposed framework for expedited review of innovative pilot projects. This would occur outside of the Phase 2 proceeding.

[8] The HECO Companies also had time-limited PIMs for cost-effective renewables procurement and demand response with deadlines of March 31, 2019 and December 31, 2018, respectively.

3. Principles of ARA Index Design

3.1 Cost Trend Research and its Use in Regulation

This section of the report considers some technical and theoretical issues that arise in statistical cost research to design revenue adjustment indexes for the HECO Companies. We begin with an introduction to input price and productivity indexes. There follows a discussion of their use in revenue adjustment index design.

Basic Indexing Concepts

Input Price and Quantity Indexes

The growth rate of a company's cost can be shown to be the sum of the growth in a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

growth Cost = growth Input Prices + growth Inputs [1]

These indexes summarize growth in the prices and quantities of the various inputs that a company uses. Capital, labor, and miscellaneous materials and services are the major classes of base rate (non-energy) inputs used by gas and electric utilities. These are capital-intensive businesses, so the heaviest weights are placed on the capital subindexes.

Productivity Indexes

The Basic Idea A productivity index is the ratio of an output quantity (aka scale) index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [2]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Some productivity indexes measure productivity *trends*. The growth of a productivity trend index is the difference between the growth of the output and input quantity indexes.

growth Productivity = growth Outputs – growth Inputs. [3]

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. Some indexes measure productivity in the use of a single input class such as labor. These indexes are sometimes called *partial* factor productivity ("PFP") indexes.

Output Indexes The output (quantity) index of a firm summarizes growth in its outputs or operating scale. If the index is multidimensional, the growth in each output dimension that is itemized is measured by a sub-index. Growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost.*[9] In that event, the index should be constructed from one or more output (aka scale) 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 an output or any other business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[10] An MFP index calculated using a cost-based output index ("$Outputs^C$") will be denoted as MFP^C.

$$growth\ MFP^C = growth\ Outputs^C - growth\ Inputs. \quad [4]$$

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

[9] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.

[10] 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.

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[11] 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 source of productivity growth driver is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required to the extent that cost tends to grow less rapidly than output. Increased capacity utilization and incremental scale economies will typically be lower the slower is output growth.[12]

A third important productivity growth driver is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. An example for a power distributor is forestation. In a suburb or rural area where forestation is increasing (due, for example, to the conversion of cropland to other uses), rising vegetation management expenses due to growing trees will cause 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 capital stock is large relative to the need to replace plant that is nearing retirement age. If a utility requires unusually high replacement capital expenditures ("capex"), capital productivity growth can be unusually slow. The utility is, effectively, replacing depreciated older facilities with newer facilities that will last for many years and may be sized to accommodate future demand growth but are for these reasons more expensive.

Productivity growth is also driven by changes in 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 is its current inefficiency.

Our analysis suggests that productivity growth can be different between utilities, and over time, for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow

[11] The seminal paper on this topic is Denny, Fuss and Waverman, *op. cit.*

[12] 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.

output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of revenue adjustment indexes. The following basic result of cost theory is useful.

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C}.\ ^{13} \qquad [5]$$

The growth in the cost of a utility is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index.

Assuming that growth in allowed revenue should track the growth in the cost of the typical utility, this result provides the basis for a revenue adjustment index of general form:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices - X + growth\ Scale^{C}_{Utility} \qquad [6a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Consumer\ Dividend. \qquad [6b]$$

Here $Scale^{C}_{Utility}$ is an index of growth in the operating scale of the subject utility. X, the "X factor," reflects the base MFP growth trend ("$\overline{MFP}^{C}$") of the industry and a consumer dividend.[14] The base MFP growth trend is typically the trend in the MFP^{C} of the regional or national utility industry. Notably, a consistent cost-based scale index should be used in the supportive MFP research.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue adjustment index. The customers variable typically has the highest estimated cost elasticity amongst the scale variables considered in econometric research on the cost of energy distributors. A scale escalator that includes volumes and/or peak demand as scale variables diminishes

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[13] An alternative basis for a revenue adjustment index can be found in index logic. Recall from relation [1] 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. Then,

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices + growth\ Scale^{C} - (growth\ Scale^{C} - growth\ Input\ Quantities) \\ &= growth\ Input\ Prices - growth\ MFP^{C} + growth\ Scale^{C} \end{aligned}$$

[14] Since the X factor often includes a consumer dividend in approved MRPs, it is sometimes said that the productivity research has the goal of "calibrating" (rather than solely determining) X.

a utility's incentive to promote DSM. This is an argument for excluding these variables from a revenue adjustment index scale escalator.

The number of customers can replace $Scale^{C}_{Utility}$ in relation [6a], with the following result:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices_{Industry} - X + growth\ Customers_{Utility} \quad [7a]$$

$$X = \overline{MFP}^{N}_{Industry} + Consumer\ Dividend.^{15} \quad [7b]$$

where $\overline{MFP}^{N}$ is the trend in an MFP index that uses the number of customers to measure output.

The HECO Companies are vertically integrated electric utilities ("VIEUs") that provide state-regulated generation and transmission services as well as distributor services. It therefore makes sense to consider a multidimensional scale index to measure VIEU output in statistical cost research to support the design of revenue adjustment indexes for these Companies.

Inflation Issues

Suppose, now, that a macroeconomic inflation index such as the GDPPI is used as the inflation measure in a revenue adjustment index. Relation [5] can be restated as:

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices - growth\ Productivity + growth\ Outputs^{C} \\ &\quad + growth\ GDPPI - growth\ GDPPI \\ &= growth\ GDPPI - [growth\ Productivity + (growth\ GDPPI - growth\ Input\ Prices)] \\ &\quad + growth\ Outputs^{C}. \end{aligned} \quad [8]$$

Relation [8] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation. This provides the basis for the following revenue adjustment index:

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X + growth\ Scale^{C}_{Utility} \quad [9a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices_{Industry}}\right) + Consumer\ Dividend. \quad [9b]$$

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[15] An equivalent formula is:
$growth\ Revenue^{Allowed} - growth\ Customers = growth\ (Revenue^{Allowed}/Customer) = growth\ Input\ Prices - X.$
This is sometimes called a "revenue per customer" index.

In addition to the base productivity trend, the X factor now includes the difference between the GDPPI and industry input price trends. The second X factor term may be called the "inflation differential."[16]

Consider now that the GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[17] It can then be shown that the trend in the GDPPI is well-approximated by the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{trend GDPPI} = \textit{trend Input Prices}_{Economy} - \textit{trend MFP}_{Economy}. \qquad [10]$$

When the GDPPI is used as the inflation measure in a revenue adjustment index, revenue growth is therefore already slowed by the MFP trend of the economy.

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

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

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

It follows that adding an inflation differential to the X factor formula involves a reduction in X by the MFP trend of the economy. Furthermore, the X factor can be stated equivalently as the sum of a productivity differential and an input price differential. The productivity differential is the difference between the MFP trends of the industry and the economy. The input price differential 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 MRPs. This approach has been especially popular in New England regulation.[18]

Regardless of whether relation [9b] or [11] are used in research to calculate the X factor, the benefit of these more complex formulations goes beyond correcting for the tendency of GDPPI to mismeasure estimated industry input price growth. Consider, for example, the trend in a revenue adjustment index that is designed in accordance with relations [9a] and [9b].[19]

[16] It can also be shown that the X factor measures the tendency of the unit costs of sampled utilities to grow more slowly than inflation.

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

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

[19] A similar result can be obtained using relations [9a] and [11].

$$\overline{Revenue}^{Allowed} = \overline{GDPPI} - \left[\overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices}_{Industry}\right)\right] + \overline{Scale}^{C}_{Utility}$$

$$= - \left(\overline{Scale}_{Industry} - \overline{Inputs}_{Industry} - \overline{Input\ Prices}_{Industry}\right) + \overline{Scale}^{C}_{Utility}$$

$$= \left(\overline{Input\ Prices}_{Industry} + \overline{Inputs}_{Industry}\right) + \left(\overline{Scale}_{Utility} - \overline{Scale}_{Industry}\right)$$

$$= \overline{Cost}_{Industry} + \left(\overline{Scale}_{Utility} + \overline{Scale}_{Industry}\right) \qquad [12]$$

The trend in a revenue adjustment index thus equals the cost trend of the industry plus the difference in the scale trends of the utility and the industry. Any tendency of the input price index used in calculations to mismeasure input price growth is then corrected.

Scale Escalators

Revenue adjustment indexes do not always include explicit scale escalators. A revenue adjustment index of general form

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X \qquad [13a]$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X + growth\ Scale_{Utility} \qquad [13b]$$

where

$$X = \overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices}_{Industry}\right) + Expected(growth\ Scale_{Utility})$$

$$+ Consumer\ Dividend. \qquad [13c]$$

It can be seen that if the MFP does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

Consumer Dividend

The consumer dividend (aka Stretch Factor) term of a rate or revenue adjustment index should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the MRP compare to those in the regulatory systems of utilities in the productivity studies used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the plan. Productivity growth should be more rapid to the extent that inefficiency is greater.

Statistical benchmarking is useful in setting stretch factors. Benchmarking can address O&M expenses, capital cost, total cost, and reliability. Sophisticated econometric cost benchmarking studies are routinely used to set stretch factors for power distributors in Ontario. Statistical cost benchmarking is also extensively used by Australian and British utility regulators.[20]

3.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on the input price and productivity trends of utilities because the technology of these companies is capital intensive. The annual cost of capital 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.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK.^{21,22} \qquad [14]$$

In electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are constructed from these same construction cost indexes and from data on the rate of return on capital.[23]

[20] PEG has prepared transnational power distribution cost benchmarking studies for both the Australian Energy Regulator and the Ontario Energy Board and benchmarks the costs of all Ontario Power distributors each year using the latest available Ontario data.

[21] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in 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.

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

[23] If taxes are included, capital prices are also a function of tax rates.

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between some monetary methods is the pattern of decay that is assumed in the service flow from the plant additions that are made each year.[24] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue adjustment indexes.

1. <u>Geometric Decay</u> ("GD"). Under the GD method, the flow of services from plant additions in a given year is assumed to decline at a constant rate over time.[25] Plant is typically valued in replacement dollars. Cost is computed net of capital gains. Replacement valuation differs from the historical (a.k.a. "book") valuation used in North American utility accounting.

   The GD capital price is a simulation of the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. The price is driven by trends in construction costs and the rate of return on capital.

2. <u>One-Hoss-Shay</u> ("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.[26] This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this

[24] 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.

[25] The quantity of capital at the end of each period *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:

$$XKt = XK_{t-1} \cdot (1-d) + XKA_t$$
$$= XK_{t-1} \cdot (1-d) + \frac{VKA_t}{WKA_t}.$$

Here *d* is the (constant) rate of decay in the quantity of older capital. The quantity of capital added each year is calculated by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*").

[26] 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").

$$XK_t = XK_{t-1} + XKA_t - XKR_t.$$
$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}.$$

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.

constant flow assumption has, due to data limitations, been applied to the total plant additions for groups of assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional COS ratemaking.[27] Replacement valuation of plant, capital gains, and use of capital service prices can all give rise to volatile capital prices that complicate the identification of inflation (and input price) differentials. The derivation of a revenue adjustment index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile, making the identification of sensible inflation and input price differentials easier.

Kahn Method

The Kahn method for calibrating X factors was developed by noted Cornell University regulatory economist Alfred Kahn and is used by the Federal Energy Regulatory Commission ("FERC") to set the X factors in the price cap indexes of interstate oil pipelines.[28] PEG has developed a variant of the original Kahn method which we believe is more useful in X factor research. In an application to the HECO Companies, we would calculate trends in the cost of base rate inputs of a sample of VIEUs using FERC Form 1 data and capital cost accounting like that used in Hawaii and then solve for the value of X which would have caused the trend in VIEU cost to equal the trend in a revenue adjustment index. This analysis could exclude itemized costs that are likely to be addressed by trackers and riders in the Companies' new PBR plan. The X factor resulting from such a calculation reflects the inflation differentials of sampled utilities as well as their productivity trends without having to itemize them.

[27] The OHS assumptions are more markedly different.

[28] See, for example, FERC Orders 561 and 561-A.

Stated differently, the X factor would reflect the input price and productivity differentials of utilities combined.

3.3 Application to the HECO Companies

To develop an X factor for the HECO Companies, a rigorous, thorough, and complex approach would be to use the latest available data (e.g., through 2018) from the FERC and other reputable sources to 1) develop a scale index using econometric research on VIEU cost to identify scale variables and their cost elasticities and 2) calculate the average productivity trend and inflation differential of the sampled utilities.[29] An X factor could instead be calculated using a simpler "Kahn Method" exercise.

Some special considerations are also pertinent in choosing X factors for the HECO Companies. These Companies will have trackers for costs of major plant additions. However, major plant additions typically account for less than half of each Company's capex. There may be markdowns on the capex that is otherwise eligible for tracker treatment. Moreover, the revenue adjustment indexes will not include scale escalators. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes.

[29] We could, alternatively, use the same data to calculate input price and productivity differentials consistent with relation [11].

4. Salient Precedents

This section of the report discusses precedents for energy utility rate and revenue adjustment indexes with designs that were informed by cost trend research. Most of these precedents pertain to MRPs for gas and electric power distributor services. We also review provisions for supplemental capital revenue when funding from rate and revenue adjustment indexes is otherwise expected to be insufficient.

4.1 Revenue Adjustment Indexes

Table 1 provides a summary of approved North American revenue adjustment indexes with designs that were informed by cost trend research. It can be seen that the majority have included a scale escalator. Most commonly, growth in allowed revenue equals inflation – X + customer growth. Large utilities that have operated under this general approach to revenue escalation include ATCO Gas in Alberta, Enbridge Gas Distribution in Ontario, Hydro-Québec Distribution, Southern California Edison, and Southern California Gas.[30] Utilities in other jurisdictions have had formulas like this to adjust the revenue for certain cost *components*. A plan for FortisBC, for example, has revenue adjustment indexes for O&M expenses and routine plant additions.

4.2 Inflation Measures

Table 2 provides information on the inflation measures used in approved rate and revenue adjustment indexes. It can be seen that U.S. indexes typically rely on a single macroeconomic inflation measure to make inflation adjustments. Of these, the GDPPI has been the most popular by far. This is due in part to the fact that the GDPPI is less sensitive to fluctuations in food and energy commodity prices than consumer price indexes. More customized industry-specific inflation measures have been popular in recent Canadian MRPs.

[30] The Régie de l'énergie in Québec has also ruled that the largest provincial gas utility, Énergir, will prospectively operate under such an index.

Table 1

Approved Revenue Cap Indexes Informed By Cost Trend Research[1]

Applicable Services	Utility	Jurisdiction	Plan Term	Scale Escalator(s)
Gas Distribution	Southern California Gas	California	1997-2002	Customers
Gas Distribution	BC Gas	British Columbia	1998-2000	Customers, Service Line Additions, etc.[2]
Power Distribution	Southern California Edison	California	2002-2003	Customers
Bundled Power Service and Gas Distribution	Pacific Gas and Electric	California	2004-2006	None
Gas Distribution	Southern California Gas	California	2005-2007	None
Gas Distribution	Gaziféré	Québec	2006-2010	Customers
Gas Distribution	Vermont Gas Systems	Vermont	2006-2009, extended to 2015	Customers
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Customers
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	None
Power Distribution	Green Mountain Power	Vermont	2010-2013	None
Gas Distribution	Gaziféré	Québec	2011-2015	Customers
Gas Distribution	All Distributors	Alberta	2013-2017	Customers
Bundled Power Service	FortisBC	British Columbia	2014-2019	Customers
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Customers, etc.[2]
Gas Distribution	All Distributors	Alberta	2018-2022	Customers
Power Distribution	Eversource Energy	Massachusetts	2018-2023	None
Power Distribution	Hydro-Québec	Québec	2018-2022	Customers
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	None

[1] Shaded plans have expired.

[2] There are separate revenue cap indexes for O&M expenses and various kinds of capex in these plans that in some instances have different scale escalators. For example, the annual scale escalator for services capex is the number of service additions.

Table 2

Base Productivity Trend, Consumer Dividend, and X Factor Decisions in North American PBR Proceedings[1]

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Consumer Dividend[2]	X-Factor [3,4]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Oil Pipelines	All U.S.	United States	1995-2001	Price Cap	PPI-Finished Goods	NA	NA	1.00%
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario Distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Oil Pipelines	All U.S.	United States	2001-2006	Price Cap	PPI-Finished Goods	NA	NA	0.00%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDP IPI Canada	NA	NA	1.00%
Oil Pipelines	All U.S.	United States	2006-2011	Price Cap	PPI-Finished Goods	NA	NA	-1.30%
Power Distribution	NSTAR	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 2 (Continued)

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Consumer Dividend[2]	X-Factor [3,4]
Oil Pipelines	All U.S.	United States	2011-2016	Price Cap	PPI-Finished Goods	NA	NA	-2.65%
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2020	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%
Oil Pipelines	All U.S.	United States	2016-2021	Price Cap	PPI-Finished Goods	NA	NA	-1.23%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%
Power Distribution	Hydro-Québec	Québec	2018-2022	Revenue Cap	Industry-specific	NA	0.00%	0.30%
Power Distribution	Eversource Energy[5]	Massachusetts	2018-2023	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.31%
Gas Distribution	Amalco	Ontario	2019-2023	Price Cap	GDPPI	0.00%	0.30%	0.30%
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	Revenue Cap	Industry-specific	0.00%	0.30%	0.30%

		Acknowledged Productivity Trend	Consumer Dividend	X-Factor
Averages*	**All Current and Expired Plans**	**0.56%**	**0.37%**	**0.73%**
	All Current Plans	**0.20%**	**0.22%**	**0.14%**
	All Current Canadian Plans	**0.31%**	**0.21%**	**0.49%**
	All Current U.S. Plans	**-0.46%**	**0.25%**	**-1.27%**

*Averages exclude X factors that are percentages of inflation.

[1] Shaded plans have expired.

[2] Some approved X factors are not explicitly constructed from such components as a base productivity trend and a consumer dividend. Many of these are the outcome of settlements.

[3] X factors may not be the sum of the acknowledged productivity trend and the consumer dividend, where these are itemized, for reasons that include the following: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism or (2) the X factor may incorporate additional adjustments to account for special business conditions.

[4] North American X factors typically include any consumer dividend that has been explicitly or implicitly approved.

[5] The approved X factor for Eversource Energy did not include the consumer dividend. To ensure consistency across examples, we have recalculated the X factor here, assuming that the 0.25% consumer dividend will be applied in all years.

4.1 Productivity Differentials

Table 3 documents instances in which regulators have reduced X factors by the MFP trend of the national economy when a macroeconomic inflation measure was used in a rate or revenue cap index. We noted in Section 3.1 that this is typically done with an explicit productivity differential term in the X factor formula. Table 3 includes *all* known instances of an explicit productivity differential in approved X factors for *energy* utilities along with a *sampling* of the analogous adjustments in indexes for *telecommunications* ("telecom") utilities. We believe that there are many more instances of productivity differentials in approved telecom-utility X factors.

Table 3

Precedents for Productivity Differentials in the Calculation of Approved X Factors

Applicable Services	Company	Jurisdiction	Plan Term	Inflation Measure	Case Reference
Energy					
Power Distribution	Eversource Energy	Massachusetts	2018-2022	GDPPI	DPU 17-05; November 2017
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	GDPPI	Docket DTE 05-27
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2001	GDPPI	Docket D.P.U. 96-50-C (Phase I); May 1997
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, Terminated in 2010	GDPPI	Docket DTE 03-40
Gas Distribution	Union Gas	Ontario, Canada	2001-2003	GDP IPI Canada	RP-1999-0017; July 2001
Power Transmission & Distribution	Power & Water	Australia - Northern Territory	2009-2014	CPI Australia	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Bundled Power Service	Jamaica Public Service	Jamaica	2015-2019	CPI Jamaica adjusted for U.S. inflation	Jamaica Public Service Company Limited Tariff Review for Period 2014-2019 Determination Notice
Power Distribution	All	New Zealand	2004-2009	CPI New Zealand	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Power Distribution	All	New Zealand	2010-2015	CPI New Zealand	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009
Telecommunications					
Telecom	SNET	Connecticut	1996-2001	GDPPI	Docket 95-03-01
Telecom	Ameritech	Illinois	1995-2002	GDPPI	Case 92-0048/93-0239
Telecom	NYNEX	Massachusetts	1995-2001	GDPPI	D.P.U. 94-50
Telecom	Interstate access services of LECs	US National	1997-2000	GDPPI	Docket 97-159
Telecom	BC Tel, Bell Canada, Island Tel, MTT, MTS, NB Tel, TELUS	Canada National	1998-2001	GDPPI	CRTC 97-9
Telecom	NYNEX	New York	1995-1999	GDPPI	Case 92-G-0665

4.2 Kahn Method

The FERC has approved Kahn method X factors for the price cap indexes of interstate oil pipelines five times. The current Oil Pipeline Index escalates prices by the Producer Price Index ("PPI") for Finished Goods plus 1.23%, indicating an X factor of -1.23%.[31] The prior index escalated prices by the PPI for Finished Goods plus 2.65%, indicating an X factor of -2.65%.[32] The Régie de l'énergie in Quebec recently relied on the Kahn method in part to set the X factor of a revenue cap index for the O&M expenses of Hydro Quebec Transmission.[33]

4.3 Base Productivity Trends, Consumer Dividends, and X Factors

Table 2 and Figures 1 and 2 provide summaries of the explicit base productivity trends, consumer dividends, and X factors in energy utility rate and revenue cap indexes that have been approved by North American regulators and informed by cost trend research. The following results are notable.

- The base productivity trends and consumer dividends have fallen over the years. The average of the acknowledged base productivity trends in current plans is 0.20%. The Ontario Energy Board has approved 0% base productivity trends on several recent occasions. The Massachusetts Department of Public Utilities ("DPU") recently acknowledged a -0.46% productivity trend for U.S. power distributors. The average of the approved consumer dividends in current plans is 0.22%.
- X factors have also trended downward over time. The average X factor in current plans is 0.14%. The current -1.27% average for U.S. plans is well below the current 0.49% average for Canadian plans.
- The X factors reported in Table 2 are inclusive of any approved consumer dividends, whereas Hawaii's PUC has decided to have a separate consumer dividend. The average current X factor exclusive of any explicitly-approved consumer dividend is about -0.04%. The average for U.S. plans is -1.40% whereas the average for Canadian plans is about 0.30%.

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[31] FERC (2015), *Order Establishing Index Level*, FERC Docket No. RM15-20-000, December.

[32] FERC (2010), *Order Establishing Index for Oil Price Change Ceiling Levels*, FERC Docket No. RM10-25-000, December.

[33] Régie de l'énergie (2019), Decision 2019-060, R-4058-2018, May, p. 35-36.

Figure 1

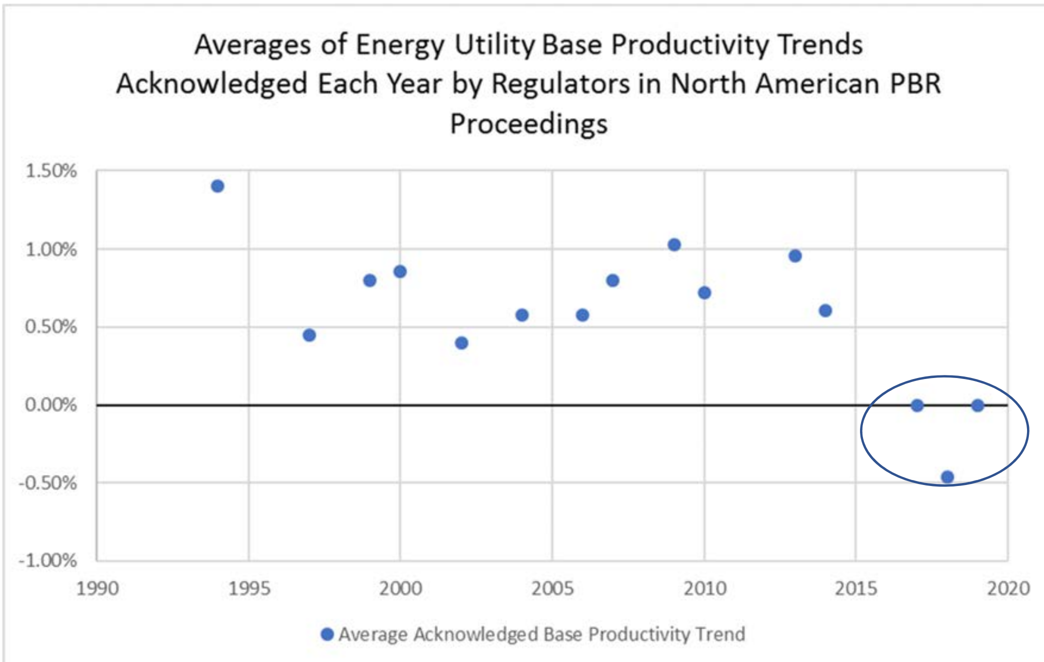
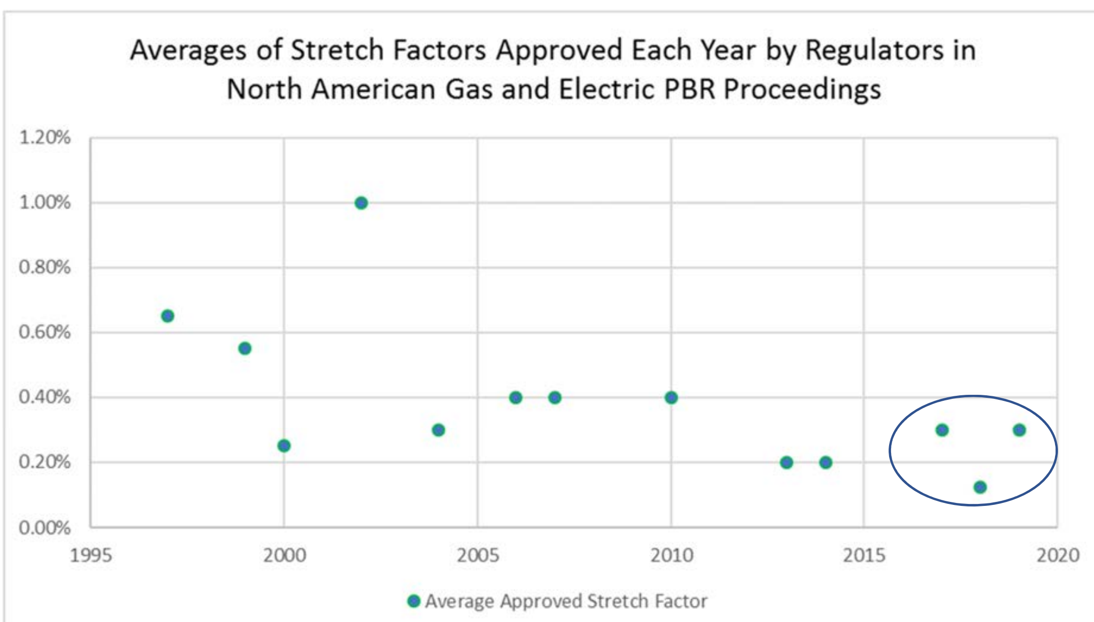


Figure 2



4.4 Making Sense of Negative X Factors for Energy Distributors

The tendency of X factors to be lower in the United States than in Canada and to be trending negative under current business conditions merits some explanation. We noted above that base productivity growth rates acknowledged by regulators have been trending downward. Most of the studies that inform these decisions pertain to energy distributors. Reasons for declines in the acknowledged MFP growth trends of energy distributors include the following.

- Growth in the number of customers served and system use has been slowed by sluggish economic growth since the Great Recession of 2008. Growth in system use (e.g., peak load) has also been slowed by expanded demand-side management ("DSM") programs. Slow growth in customers and system use reduces opportunities for distributors to increase capacity utilization and realize incremental scale economies. Utilities must still incur the costs of owning, operating, and maintaining capacity that was built in an era of more optimistic demand growth projections. Less important but notable is the related fact that slow growth in the number of *gas* customers served by combined gas and electric utilities has reduced opportunities to realize incremental economies of *scope* from the shared use of certain inputs (e.g., in billing and collection).

- Some distributors have made sizable investments in facilities that create benefits that are not captured by the output indexes commonly used to measure energy distributor productivity. For example, some distributors have been asked by their regulators to improve system reliability and/or resiliency. In the last ten years particularly, many distributors have added automated metering infrastructure ("AMI") that can reduce the duration of outages and facilitate peak load management.

- In a few states, such as Hawaii and California, growth in distributed generation ("DG") on the customer side of the meter has challenged distributors to handle intermittent DG power surpluses and honor highly volatile requests for power deliveries from the grid. Peak loads may still be quite high.

- Some utilities are accelerating replacement of distribution plant approaching retirement age. Long-term costs are often reduced by choosing replacement assets with lengthy service lives, and by sizing these facilities so that they can handle some future demand growth. These assets thus are typically much more costly to own than the highly-depreciated assets that they replace. For replacement capex and smart grid facilities alike, the impact on distributor revenue requirements is magnified by the historical cost accounting that is commonly used for capital assets in North American rate regulation.

In the United States, low X factors are also encouraged by the tendency, noted in Section 4.2 above, to use macroeconomic inflation indexes such as the GDPPI as the sole basis for the inflation factors in rate and revenue adjustment indexes. As explained in Section 3.1, the X factor should in this case reflect the difference between the GDPPI and utility input price trends. Growth in the cost of constructing power distribution facilities was unusually rapid from 2004 to 2008, and has not been offset by a subsequent period of unusually slow construction cost growth.

GDPPI growth is slowed by the MFP growth trend of the economy, and this has prompted regulators to reduce the X factor by this trend on numerous occasions. Table 4 shows that the MFP trend of the U.S. economy has averaged a substantial 0.94% annual growth between 1997 and 2017. This compares to 0.20% average annual MFP growth in Canada for the same timeframe.

An example of a negative X factor in a U.S. plan is that recently approved by the Massachusetts Department of Public Utilities for power distributor services of Eversource.[34] The Department stated in its decision that

> In the context of a PBR, a productivity offset, or X factor, is the difference between the differential in expected productivity growth between the electric-distribution industry and the overall economy and the differential in expected input price growth between the overall economy and the electric distribution industry.[35]

and that

> The Attorney General notes that no other jurisdiction in North America has approved a negative X factor to date. This fact does not, however, preclude the possibility of an X factor that is negative. In fact, other jurisdictions have acknowledged that an X factor may be positive or negative. Whether an X factor is positive or negative is determined solely by the relationship between outputs and inputs in a given industry, and there is no reason to dismiss the possibility that the electric distribution industry may be in a period exhibiting

[34] The operations to which this MRP applies were previously performed by Boston Edison, Western Massachusetts Electric, and Cambridge Electric Light.

[35] Massachusetts D.P.U. 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017, p. 381.

Table 4

MFP Trends of the U.S. and Canadian Economies

Year	United States		Canada	
	MFP[1]	Growth Rate	MFP[2]	Growth Rate
1961	56.05		79.48	
1962	58.09	3.57%	82.07	3.21%
1963	59.78	2.87%	84.07	2.41%
1964	62.11	3.82%	85.93	2.19%
1965	64.12	3.18%	87.12	1.38%
1966	66.07	3.00%	87.44	0.37%
1967	66.13	0.09%	85.86	-1.82%
1968	67.79	2.47%	88.99	3.58%
1969	67.52	-0.40%	90.49	1.67%
1970	67.35	-0.25%	91.44	1.04%
1971	69.45	3.07%	92.24	0.87%
1972	71.42	2.81%	94.07	1.96%
1973	73.38	2.70%	95.10	1.09%
1974	70.83	-3.54%	93.85	-1.33%
1975	71.47	0.90%	93.40	-0.48%
1976	74.06	3.56%	97.06	3.85%
1977	75.32	1.69%	98.89	1.87%
1978	76.41	1.43%	99.25	0.36%
1979	75.85	-0.73%	97.91	-1.36%
1980	74.11	-2.33%	95.90	-2.07%
1981	74.37	0.35%	96.24	0.35%
1982	72.10	-3.10%	94.99	-1.30%
1983	74.16	2.82%	96.67	1.75%
1984	76.29	2.84%	99.82	3.20%
1985	77.26	1.26%	101.28	1.46%
1986	78.52	1.62%	99.89	-1.38%
1987	78.65	0.17%	100.12	0.22%
1988	79.28	0.80%	100.26	0.14%
1989	79.58	0.38%	99.26	-1.00%
1990	79.90	0.40%	97.65	-1.63%
1991	79.57	-0.41%	94.87	-2.89%
1992	82.03	3.04%	95.52	0.68%
1993	81.70	-0.40%	96.45	0.97%
1994	82.11	0.50%	98.98	2.59%
1995	82.07	-0.05%	99.23	0.25%
1996	83.16	1.32%	98.25	-1.00%
1997	84.04	1.05%	99.27	1.03%
1998	85.32	1.51%	99.95	0.68%
1999	87.20	2.18%	102.43	2.46%
2000	88.66	1.66%	104.81	2.30%
2001	89.20	0.61%	104.73	-0.08%
2002	91.04	2.04%	105.83	1.05%
2003	93.36	2.51%	105.17	-0.63%
2004	95.52	2.29%	104.88	-0.27%
2005	96.98	1.51%	104.82	-0.06%
2006	97.43	0.46%	103.87	-0.91%
2007	97.90	0.48%	102.67	-1.16%
2008	96.81	-1.13%	100.23	-2.41%
2009	97.20	0.40%	97.54	-2.72%
2010	99.70	2.55%	99.02	1.51%
2011	99.44	-0.27%	100.43	1.41%
2012	100.00	0.57%	100.00	-0.43%
2013	100.36	0.36%	100.90	0.89%
2014	100.78	0.42%	102.49	1.56%
2015	101.66	0.86%	101.46	-1.01%
2016	101.10	-0.55%	101.42	-0.04%
2017	101.48	0.37%	103.31	1.85%
2018	102.48	0.98%		
Average Annual Growth Rates				
1962-1996		**1.13%**		**0.61%**
1998-2017		**0.94%**		**0.20%**
1999-2018		**0.92%**		**NA**
2008-2017		**0.36%**		**0.06%**
2004-2018		**0.62%**		**NA**
2009-2018		**0.57%**		**NA**

[1] Net Multifactor Productivity and Cost, Private Business Sector (Excluding Government Enterprises), Bureau of Labor Statistics, March 21, 2019, Office of Productivity and Technology, Division of Major Sector Productivity

[2] Statistics Canada. Table 36-10-0208-01, Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by industry

> changes that result in decreasing output given a similar or increasing level of inputs.[36]

The Department acknowledged a productivity differential of -1.35% and an input price differential of -1.29%. A witness for a consumer advocate also supported a negative X factor despite his finding of a positive industry MFP trend.

Negative X factors have also been approved by energy utility regulators in Britain and Australia. In both countries, revenue adjustment indexes have hybrid designs in which an inflation-X formula is used but X reflects multiyear cost and inflation forecasts. One example is found in the 2006 British Transmission Price Control Review Final Proposals. Ofgem approved an Inflation + 2% price control for electric transmission utilities "to ensure that revenues, and associated cash flows are aligned more closely to the rising trend of costs resulting from the substantial increase in investment envisaged over the 5-year period."[37]

The Brattle Group's report, presented as Exhibit 2 to the HECO Companies' January 4th brief in Phase 1 of this proceeding, outlined several recent revenue cap precedents for Australian and British power distributors.[38] The authors reported that the current MRPs for all five power distributors in the populous state of Victoria, Australia allowed annual increases in authorized revenues in excess of inflation, and that these averaged 1.8%. The Brattle Group also found that in the most recently completed round of MRPs for British power distributors, 13 of 14 distributors had allowed revenue growth in excess of inflation. Real revenue increases for British power distributors averaged nearly 6% annually.

The Brattle Group's report also discussed the recent revenue requirement trends of the three large California energy utilities. They found that for the 2007-2018 period, authorized base revenues for these utilities increased 2.5% more rapidly than the growth in the GDPPI on average.[39]

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[36] *Ibid*., p. 382.

[37] Ofgem, *Transmission Price Control Review Final Proposals*, December 4, 2006, p. 7.

[38] Toby Brown and William Zarakas (2019), "*Improving the PBR Framework in Hawai'i Addressing the Risk of 'Capex Bias.'*" p. 9.

[39] *Ibid*., p. 10.

4.5 Provisions for Supplemental Capital Revenue

Our discussion of the drivers of productivity growth in Section 3.1 suggests that utilities can have expected productivity growth during an MRP which falls short of the industry norm due to adverse circumstances that are beyond their control. These circumstances include unusually slow demand growth and an unusually large need to replace plant. Regulators in several jurisdictions have recognized this problem and approved mechanisms to provide supplemental capital revenue when rate and revenue adjustment indexes are not expected to fully fund plant additions during the term of an MRP. We discuss here recent precedents from three Canadian jurisdictions.

Ontario

The Ontario Energy Board ("OEB") regulates more than 60 power distributors today. Most of these operate under MRPs called incentive regulation mechanisms ("IRMs"). In these plans, rates are initially set based on rate cases with forward test years. Distribution system plans ("DSPs") are filed. Rates in later plan years are escalated by price cap indexes with I-X formulas. The X factor for each utility is the sum of a common base productivity trend and a custom stretch factor that reflects the results of an econometric benchmarking study that is updated annually. The base productivity trend is the historical MFP trend of a power distributor peer group.

Distributors have several options for obtaining supplemental capital revenue. One option is capital modules. There are two types of capital modules available: Advanced Capital Modules ("ACMs") and Incremental Capital Modules ("ICMs"). An ACM may be requested only during rate cases to address projects outlined in the distributor's DSP, while an ICM may be requested between rate cases to address projects not included in a distributor's DSP, projects which have increased substantially in size and/or scope since the approval of the DSP, and projects whose eligibility could not be determined during the rate case.

For either type of capital module, distributors must demonstrate that the capex driving the supplemental funding request is eligible, prudently incurred, material, and the most cost-effective option for ratepayers. Distributors overearning by more than 300 basis points cannot request a capital module.

The amount of capex needed must exceed a materiality threshold defined by the OEB and must clearly have a significant influence on the operation of the distributor. The threshold has a markdown factor. If a project qualifies for a capital module, recovery of the annual cost of the eligible plant additions is realized via rate riders. Distributors who receive approval for rate relief through a capital module are required to report their plant additions annually. Underspends will result in refunds to ratepayers. Overspends are reviewed for prudence in rate rebasing proceedings. If the overrun is prudently incurred, the amount will be included in rates.

Ontario distributors can also request a Custom Incentive Rate-setting ("Custom IR") plan. This option is designed for distributors that expect to undertake large capital projects lasting several years. This option allows distributors to develop rate or revenue cap indexes based on forecasts of total O&M and capital spending. These forecasts should be informed by the OEB-sponsored productivity and benchmarking analyses. In several cases, this has taken the form of the distributor proposing a rate or revenue adjustment index with the following escalation formula:

$I - X + C.$

Here the term C, called the "C factor", is the supplemental annual rate or revenue growth (as applicable) needed to fund proposed capital cost growth. X is fixed for the plan term as the sum of the approved base productivity trend and a stretch factor supported by benchmarking evidence. The growth in the revenue requirement for capex is, effectively, the growth in proposed capital cost less the X factor.

To allay concerns of distributors overestimating cost and capex, Custom IR plans have in several instances included earnings sharing mechanisms and mechanisms to return the revenue requirement impact of cumulative capex underspends to customers during rate rebasing proceedings at the end of the plan term. In its most recent decision approving a Custom IR plan for Hydro One Networks' distribution services, the OEB also adopted an additional 0.15% stretch factor to apply solely to the C term beyond the stretch factor applied to the entire revenue requirement.

British Columbia

In 2014 the British Columbia Utilities Commission ("BCUC") approved a return to MRPs for FortisBC Energy (formerly Terasen Gas) and FortisBC (formerly West Kootenay Power) after several years of more traditional regulation. Unlike MRPs in many jurisdictions, these plans escalate budgets for O&M expenses and certain plant additions with separate formulas that are based on inflation and the growth of operating scale less an X factor. The FortisBC plan has one formula for capex which features the number of customers as the scale escalator. FortisBC Energy has one formula for growth-related capex and a second formula for sustainment and other capex. These formulas use the service line additions and the number of customers, respectively, as the scale escalators.

All of these index formulas are designed to escalate the allowed capex of projects that are smaller, more routine, and predictable. Capital costs for projects that are larger, more unusual in nature, and less predictable are tracked, along with the cost of all older plant. Projects that have been approved for capital cost tracking to date include FortisBC Energy's biomethane projects, FortisBC's deployment of AMI, and both companies' capitalized pensions and other post-employment benefits.

A substantial effort was undertaken in BC to determine tracker eligibility criteria for capex.[40] This effort extended beyond the initial PBR proceeding with a decision reached in 2015, more than a year after the PBR plan started. The BCUC approved materiality thresholds for levels of eligible capex based on the updated Certificate of Public Convenience and Necessity materiality thresholds of $20 million for FortisBC and $15 million for FortisBC Energy for individual projects.[41] The BCUC rejected proposals for additional tracker eligibility criteria.

This decision also addressed several concerns about possible gaming and double counting issues. The companies are required to show in each capital tracker application that the eligibility criteria had not been met by a combination of smaller projects that would normally be funded by the index-based escalators. Individual application proceedings will include an opportunity for the impact of the project on O&M expenses to be considered.

Alberta

Most Alberta energy distributors have operated under MRPs with rate or revenue adjustment indexes since 2013. The Alberta Utilities Commission has developed two generations of MRPs in generic proceedings. In these plans, rates or (for gas distributors) revenues per customer are escalated by indexes with I-X formulas. The X factor for each distributor is the sum of a common base productivity trend and stretch factor. Concerns about ensuring that the distributors have sufficient funding for capex have led to provisions for supplemental funding in both generations of MRPs approved to date.

The current MRPs allow for two methods by which distributors may obtain supplemental funding based on the kind of capex. Capital cost trackers may be requested to provide supplemental

[40] The BCUC refers to these criteria as capital exclusion criteria, meaning exclusion from formulaic escalators.
[41] FortisBC Energy's biomethane projects were not required to meet this threshold in order to have the projects' costs tracked.

funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[42] Distributors must also show that this capex resulted in a revenue requirement impact that exceeded a materiality threshold of 4 basis points of ROE.

Supplemental funding for all other eligible capex is provided by a mechanism known as the K-bar. A base K-bar value was established for each distributor for the first year of the plan based on its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, which were not funded by base rates. K-bar values in subsequent years have been escalated by the growth in the attrition relief mechanism and billing determinants.

[42] In the first generation of PBR plans, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

5. Empirical Research for HECO

Our review of rate and revenue adjustment index precedents in Section 4 reveals that few pertain to vertically-integrated electric utilities like the HECO Companies. Moreover, the HECO Companies face special operating conditions that may affect the appropriate design of their revenue adjustment indexes. For example, an unusually large and growing share of HECO's customers own distributed photovoltaic generation facilities and HECO's generation, transmission, and distribution facilities must handle their power surpluses and accommodate large diurnal swings in their demand for power deliveries.

HECO retained PEG to undertake preliminary statistical cost research to support the design of custom revenue adjustment indexes in Phase 1 of this proceeding. Results of this research were presented in reports attached to two of the Companies' Phase 1 submissions.[43] We present in this section of the report the results of some further empirical research that we have undertaken since the Commission's Phase 1 decision.

5.1 Data

The primary source of the cost and quantity data for our empirical research in this proceeding has been 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 this 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 our sample from all investor-owned electric utilities in the United States that provide generation, transmission, and distribution services sufficient to meet most local requirements and that, together with any important predecessor companies, have reported the necessary data continuously since 1964 (the benchmark year for our capital cost research). To be

[43] Hawaii PUC, Proceeding 2018-0088, "*Metrics Brief of the Hawaiian Electric Companies*," Exhibit 1, "*Regulatory Reform for the Hawaiian Electric Companies*," filed January 4, 2019 and "*Statement of Position of the Hawaiian Electric Companies,*" Exhibit B, "*Response to Staff Discussion on the Revenue Cap Index,"* filed March 8, 2019.

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

included in the PEG study, the data also were required to be of good quality, plausible, and free of special processing complications. Data from 45 utilities which met these standards were used in our research. We believe that these data are useful for statistical research to design revenue adjustment indexes for VIEUs. Table 5 lists the utilities from which PEG's sample were drawn.

5.2 Sample Period

The full sample period for our research was 1997-2017 for the Kahn and input price research and 1996-2017 for the econometric research. This sample permits the calculation of cost trend growth rates from 1997 to 2017. Data for 2018 are now available, and we may update our results later in the proceeding to reflect them.

5.3 Costs

The total cost of VIEU services considered in our study was the sum of applicable capital costs and O&M expenses. Costs were excluded from the research for various reasons. Some costs are not incurred by the HECO Companies or are expected to be addressed by trackers in the MRPs. We excluded the following costs from our calculations on these grounds:

- Generation fuels and other power supply inputs that include purchased power
- Other nuclear and all hydroelectric generation inputs
- Pensions and other benefits
- Taxes and franchise fees.

We excluded load dispatching, transmission by others, and miscellaneous transmission expenses out of a concern that the trend in these costs has been affected by the establishment of independent system operators in some regions of the U.S.[45] Customer service and information expenses were excluded out of a concern that, for many sampled utilities, these costs have become bloated with large DSM expenses that HECO does not incur. Utilities report administrative and general expenses, general plant costs, and amortization expenses on a consolidated basis. Since we excluded costs of some operations (e.g., nuclear generation) from the study, we included sensible *shares* of these consolidated costs rather than the entirety of these costs from the econometric and Kahn method research.

[45] These operators may also take the form of regional transmission organizations.

Table 5

Sample of Utilities Used in Empirical Research

Alabama Power	Louisville Gas & Electric
ALLETE (Minnesota Power)	MDU Resources Group
Appalachian Power	MidAmerican Energy Company
Arizona Public Service	Mississippi Power
Avista	Monongahela Power
Black Hills Power	Nevada Power
Cleco Power	Northern States Power - MN
Duke Energy Carolinas	Oklahoma Gas & Electric
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	PacifiCorp
Duke Energy Progress	Public Service Company of Colorado
El Paso Electric	Public Service Company of Oklahoma
Empire District Electric	Puget Sound Energy
Entergy Arkansas	South Carolina Electric & Gas
Entergy Mississippi	Southern Indiana Gas & Electric
Entergy New Orleans	Southwestern Electric Power
Florida Power & Light	Southwestern Public Service
Gulf Power	Tampa Electric
Idaho Power	Tucson Electric Power
Indiana Michigan Power	Union Electric
Kansas City Power & Light	Virginia Electric & Power
Kansas Gas & Electric	Westar Energy (KPL)
Kentucky Utilities	

Total of 45 VIEUs

In our econometric and input price research we employed monetary approaches to capital cost and price measurement. This permitted a decomposition of capital cost into price and quantity indexes. A geometric decay approach was used in the econometric research. We used this specification in our previous econometric and total cost research for the HECO Companies.[46] A COS approach was used in the input price research. Further details of PEG's capital cost calculations are provided in Appendix Section A.1.

[46] Lowry, M.N. and Hovde, D., "Price Cap Index Calibration for Hawaiian Electric Company, Hawaii PUC Docket 99-0396, December 13, 1999.

5.4 Input Prices

Operation & Maintenance

Occupational Employment Statistics ("OES") survey data from the Bureau of Labor Statistics ("BLS") for 2008 were used to construct averages of the salary and wage levels for numerous occupations in the service territory of each sampled utility. We used weights that correspond to the electric utility industry. Values of each company's labor price index for other years were calculated by adjusting the level in 2008 for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. M&S prices were escalated by the GDPPI. Summary O&M input price indexes were calculated for each utility by combining the labor and M&S price subindexes using company-specific, time-varying cost share weights. The cost shares were calculated from the FERC Form 1 data.

Capital

For the input price and econometric research, construction cost indexes and rates of return on capital are needed in the calculation of capital prices. PEG calculated weighted averages of rates of return for debt and equity.[47] We computed 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.[48]

We calculated an index of market construction costs that was allowed to vary between the service territories of sampled VIEUs in 2008 in proportion to the relative cost of local construction as measured by the total (material and installation) City Cost Indexes published in RSMeans.[49] The market construction cost index values for other years of the sample period were determined for each company

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

[48] 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.

[49] RSMeans, *Heavy Construction Cost Data 2010*.

using the rates of inflation in the appropriate regional Handy Whitman electric utility construction cost index.[50]

Multifactor Input Price Index

The summary *multifactor* input price index for each U.S. utility in our sample was constructed by combining the capital and summary O&M price indexes using company-specific, time-varying cost share weights. The cost shares were calculated from the FERC Form 1 data.

5.5 Development of a Scale Index

Our first empirical task after assembling the dataset was to develop scale indexes for each sampled utility. Recall from Section 3 that multidimensional scale indexes with cost elasticity weights can be developed for vertically-integrated electric utilities like the HECO Companies. We estimated the parameters of an econometric model of the total applicable cost of VIEU base rate inputs.[51] [52]

The values of cost and all business condition variables in this cost model were logged. This means that the estimates of the parameters for these variables were also estimates of the elasticities of cost with respect to a small change in their value. The estimation was undertaken with the R statistical programming software using a procedure that corrected for autocorrelation and groupwise heteroscedasticity.

Results of this research can be found in Table 6. It can be seen that there are nine business condition variables with statistically significant and plausibly-signed parameter estimates. These include the following five scale variables which have positive parameter estimates.

- Number of retail customers
- Generation volume
- Mid-year generation capacity
- Mid-year transmission line miles

[50] Whitman, Requardt and Associates, *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore Whitman, Requardt and Associates, various issues).

[51] By total applicable cost we mean total cost less the costs that we excluded.

[52] In this exercise, total cost was divided by the input price index to enforce a prediction of economic theory that 1% growth in the prices of all inputs raises cost by 1%. This is thus a "real" cost model.

Table 6

Econometric Model of VIEU Total Cost

Explanatory Variable	Estimated Cost Elasticity	T-Statistic		P-Value
Number of Customers	0.374	15.358	***	0.000
Fossil Steam and Other Generation Volume	0.073	5.997	***	0.000
Mid-Year Generation Capacity	0.212	12.329	***	0.000
Mid-Year Transmission Line Miles	0.086	10.170	***	0.000
Ratcheted Maximum Peak Demand	0.170	7.050	***	0.000
Percentage of Capacity Scrubbed	0.121	11.762	***	0.000
Percentage of Coal Capacity or Heavy Fuel Oil	0.263	12.859	***	0.000
Percentage of Customers with AMI	0.046	3.461	***	0.001
Number of Gas Customers	-0.016	-1.201	*	0.230
Constant	20.098	1198.599	***	0.000
Trend	0.001	1.304	*	0.193
Adjusted R-squared	0.952			
Sample Period	1996-2017			
Number of Observations	990			

*Estimate is significant at the 75% confidence level
**Estimate is significant at the 95% confidence level
***Estimate is significant at the 99.9% confidence level

- Ratcheted annual maximum peak demand[53]

We also found that the cost of the sampled VIEUs was significantly higher

- the greater was the percentage of included generating capacity with facilities to scrub emissions for sulfur
- the greater was the percentage of generating capacity fueled by coal or heavy fuel oil
- the higher was the percentage of retail customers with AMI
- the lower was the number of gas customers served.

Notice also the 0.001 estimate of the trend variable parameter. This indicates that cost tended to rise by 0.1% annually from 1996 to 2017 for reasons that are not explained by the model's other variables.

Table 7 shows how the econometric elasticity estimates were used to calculate scale index weights for the five scale variables. It can be seen that cost was much more elastic with respect to the number of customers served , generation capacity, and ratcheted peak demand than it was with respect to the other two scale variables. The number of customers has a 40.9% weight in the scale index whereas generation capacity has a 23.2% weight and peak demand had an 18.6% weight. Generation volume has a weight around 7.9% and transmission line miles has a 9.4% weight.

5.6 Calculating an X for VIEUs Using the Kahn Method

To calculate an X factor for VIEUs using the Kahn Method we postulated a hypothetical generic revenue adjustment index with the following formula:

$$\textit{Growth Revenue}^{Allowed} = \textit{growth GDPPI} - X + \textit{growth Scale}^{C}_{Utility}.^{54}$$

The scale indexes used the five scale variables and elasticity weights discussed above. We also considered an alternative and simpler scale escalator that used only the number of customers as the scale variable.

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[53] The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand of the grid.

[54] A scale index was included in our Kahn method exercise even though there will probably not be scale escalators in the revenue adjustment indexes of the HECO Companies. This makes sense because the X factor would otherwise be reduced by the historical trend in the operating scale of the sampled utilities. This trend was more rapid historically than that expected for HECO going forward, especially in the early years of our full sample period.

Table 7

Cost-Elasticity Weights for the Scale Index

(derived from Table 6)

Scale Driver	Estimated Cost Elasticity[1]	Commensurate Elasticity Weight[2]
Number of Customers	0.374%	40.9%
Fossil Steam and Other Generation Volume	0.073%	7.9%
Mid-Year Generation Capacity	0.212%	23.2%
Mid-Year Transmission Line Miles	0.086%	9.4%
Peak Demand	0.170%	18.6%
Sum of the Above	0.91%	100%

[1]Defined to be the percent rise in cost due to a 1% increase in the value of the scale variable. For example, PEG's econometric research finds the cost elasticity with respect to customers to be 0.374%, i.e. a 1% increase in number of customers is associated with a 0.374% rise in cost.

[2]The formula is the estimated cost elasticity for the variable divided by the sum of all elasticity estimates.

We calculated the trend in the cost of base rate inputs for each sampled utility. In these calculations, capital cost was defined as the sum of depreciation and amortization expenses and return on average rate base. Rate base was calculated as the difference between gross plant value and accumulated depreciation expenses. We then calculated the value of X that would cause the trends in these costs of our sampled VIEUs to equal the trends in the hypothetical revenue cap indexes on average over the sample period.

The full sample period we considered was the twenty-one year 1997-2017 period. We also considered the results for the last fifteen years (2003-2017) and the last ten years (2008-2017) of the period. Key results of this research are set forth in Table 8 and Figure 3.

Table 8

U.S. VIEU Kahn X Factor Calculations[1,2]

Year	Operating Scale								Kahn X Factors	
	Total Cost	Retail Customers	Mid-Year Average Generation Capacity	Fossil Steam and Other Generation Volume	Mid-Year Average Transmission Line Miles	Ratcheted Maximum Peak Demand	Scale Index[3]	GDPPI Inflation	Using Scale Index	Using Customers
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[G]+[H]-[A]	[B]+[H]-[A]
1997	3.82%	1.80%	0.62%	5.16%	3.43%	3.74%	2.31%	1.71%	0.19%	-0.31%
1998	3.45%	1.92%	0.09%	5.60%	0.32%	3.09%	1.86%	1.08%	-0.51%	-0.45%
1999	1.06%	1.40%	-0.68%	4.25%	0.38%	2.75%	1.30%	1.42%	1.67%	1.77%
2000	6.21%	2.07%	-1.49%	2.99%	-0.68%	2.15%	1.07%	2.25%	-2.89%	-1.90%
2001	3.16%	1.51%	0.55%	1.39%	-1.14%	1.55%	1.03%	2.26%	0.13%	0.61%
2002	2.53%	1.40%	4.69%	-1.61%	0.08%	1.23%	1.77%	1.52%	0.76%	0.39%
2003	2.43%	1.33%	4.58%	-1.09%	0.19%	1.86%	1.88%	1.98%	1.44%	0.89%
2004	2.90%	1.45%	2.03%	-0.11%	-0.07%	0.37%	1.12%	2.71%	0.92%	1.26%
2005	3.79%	1.51%	2.52%	1.44%	-0.31%	2.83%	1.81%	3.17%	1.20%	0.90%
2006	4.06%	0.20%	4.26%	1.07%	-0.93%	1.82%	1.40%	3.02%	0.36%	-0.85%
2007	6.05%	1.40%	3.26%	2.33%	0.10%	1.86%	1.87%	2.63%	-1.55%	-2.02%
2008	4.54%	1.04%	2.59%	2.45%	1.21%	0.70%	1.46%	1.91%	-1.16%	-1.59%
2009	5.10%	0.60%	2.14%	-4.23%	0.98%	0.69%	0.63%	0.78%	-3.69%	-3.71%
2010	7.85%	0.52%	2.21%	-0.06%	1.03%	1.15%	1.03%	1.22%	-5.59%	-6.11%
2011	4.05%	0.44%	1.70%	3.11%	0.72%	1.06%	1.09%	2.04%	-0.92%	-1.56%
2012	2.36%	0.59%	1.39%	-2.13%	1.52%	0.40%	0.61%	1.82%	0.07%	0.05%
2013	4.30%	0.78%	1.13%	1.06%	1.05%	0.31%	0.82%	1.60%	-1.88%	-1.92%
2014	5.41%	0.81%	1.13%	2.33%	0.67%	1.13%	1.05%	1.78%	-2.57%	-2.82%
2015	4.26%	1.02%	1.59%	-1.14%	1.06%	0.73%	0.93%	1.06%	-2.27%	-2.18%
2016	5.29%	1.08%	-0.60%	-2.96%	1.08%	0.21%	0.21%	1.31%	-3.77%	-2.90%
2017	2.67%	0.85%	-0.96%	-1.69%	0.66%	0.16%	0.08%	0.89%	-1.70%	-0.93%
Average Annual Growth Rates										
1997-2017	4.06%	1.13%	1.56%	0.87%	0.54%	1.42%	1.21%	1.82%	**-1.04%**	**-1.11%**
2003-2017	4.34%	0.91%	1.93%	0.03%	0.60%	1.02%	1.07%	1.86%	**-1.41%**	**-1.57%**
2008-2017	4.58%	0.77%	1.23%	-0.33%	1.00%	0.65%	0.79%	1.44%	**-2.35%**	**-2.37%**

Notes:

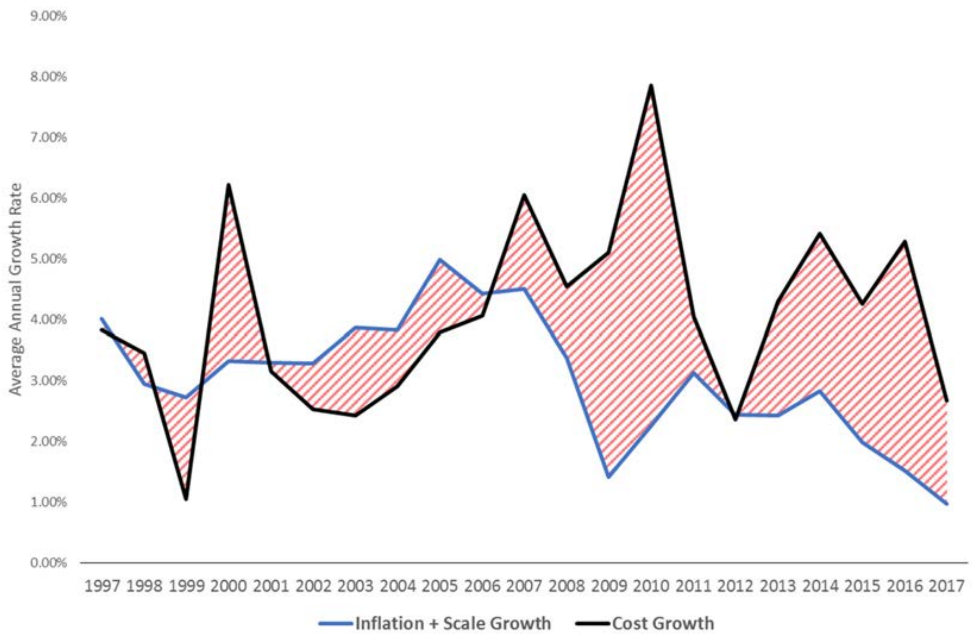
[1] Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include the costs, capacities, and volumes of conventional hydraulic, pumped storage hydraulic, and nuclear generation.

[2] All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. Elasticity weights were those displayed in Table 7. The formula becomes growth Scale [G] = 40.9% x [B] + 23.2% x [C] + 7.9% x [D] + 9.4% x [E] + 18.6% x [F].

Figure 3

How Cost Growth Outpaced Inflation + Scale Growth



For all sample periods considered, it can be seen that the average annual growth in the cost of sampled VIEUs was considerably more rapid than the average annual growth in the GDPPI. The average annual growth in the scale index was not large enough to close the gap. Thus, the X factor must be negative if the hypothetical revenue adjustment indexes are to track historical VIEU costs on average. Using the scale index, the Kahn X factor was **-1.04%** for the full 1997-2017 sample period. Similar values for X were obtained using the number of customers as the scale escalator in the hypothetical revenue cap indexes.

The Kahn X factors are even more negative for more recent sample periods. Growth in the costs of the sampled VIEUs accelerated while GDPPI inflation and growth in their scale indexes both decelerated. Using the scale index, the indicated X factor fell to **-1.41%** for the last fifteen years (2003-2017) and to **-2.35%** for the last 10 years (2008-2017).

5.7 Explaining Negative X Factors for VIEUs

We have undertaken research to understand the increasingly negative values of the Kahn X factors for VIEUs. Table 8 sheds some light on the problem inasmuch as the difference between the trends in the cost and operating scale of the utilities is their unit cost trends. The unit cost trend averaged 2.85% over the full sample period, and this exceeded the 1.82% average growth of the GDPPI by 103 basis points. Since 1997, unit cost growth has accelerated while GDPPI growth has decelerated.

Digging deeper, relations [9a] and [9b] inform us that when the GDPPI is used as the sole inflation measure in a revenue adjustment index, the X factor should reflect the productivity trend of the industry and the differential between industry input price and GDPPI inflation. For each VIEU in the sample we calculated multifactor indexes of growth in the prices of each utility's base rate inputs. In these calculations, we used a COS capital price index designed to mimic the traditional cost of service treatment of capital cost. We used these indexes to calculate the inflation differential for each company in the sample.

Results of this exercise can be found in Table 9. It can be seen that the growth trend in the industry input price index was substantially more rapid than that of the GDPPI. Over the full 1997-2017 sample period, for example, industry input price growth exceeded GDPPI growth each year by 0.99% on average. Growth in the cost of constructing many kinds of electric utility facilities was especially rapid from 2004 to 2008. The inflation differential was a similar -0.86% for the last fifteen years of the sample period but worsened to -1.38% over the last ten years, due chiefly to a slowdown in GDPPI inflation.

The difference between the Kahn X factor and the inflation differential is a rough estimate of the multifactor productivity trend of VIEUs.[55] Table 9 shows that it was -0.05% over the full sample period and declined to -0.54% over the last fifteen years of the period and to -0.97% over the last ten years.[56]

Table 10 shows the trends in various components of utility cost which contributed to the recent productivity slowdown. It can be seen that growth in the capital cost of VIEUs was much more rapid

[55] The basis for this statement is that if

$$X^{Kahn} = \overline{MFP} + (\overline{GDPPI} - \overline{Input\ Prices})$$

then

$$\overline{MFP} = X^{Kahn} - (\overline{GDPPI} - \overline{Input\ Prices}).$$

[56] This finding is consistent with the 0.001 estimate of the trend variable parameter in the econometric total cost model.

Table 9

Inflation Differential and Its Impact on X

Year	Kahn X Factor	GDPPI	Industry Input Price Growth	Inflation Differential	Residual X Resulting from Productivity and Other Factors
	[A]	[B]	[C]	[D] = [B] - [C]	[E] = [A] - [D]
1997	0.19%	1.70%	3.72%	-2.01%	2.20%
1998	-0.51%	1.08%	3.98%	-2.90%	2.39%
1999	1.67%	1.42%	0.61%	0.81%	0.85%
2000	-2.89%	2.25%	5.71%	-3.46%	0.57%
2001	0.13%	2.26%	2.04%	0.22%	-0.08%
2002	0.76%	1.52%	1.98%	-0.47%	1.22%
2003	1.44%	1.98%	2.10%	-0.12%	1.55%
2004	0.92%	2.71%	2.33%	0.37%	0.55%
2005	1.20%	3.17%	2.30%	0.87%	0.32%
2006	0.36%	3.02%	2.89%	0.13%	0.23%
2007	-1.55%	2.63%	3.08%	-0.45%	-1.10%
2008	-1.16%	1.91%	4.00%	-2.09%	0.93%
2009	-3.69%	0.78%	2.99%	-2.20%	-1.48%
2010	-5.59%	1.22%	3.01%	-1.79%	-3.81%
2011	-0.92%	2.04%	2.70%	-0.65%	-0.26%
2012	0.07%	1.82%	2.41%	-0.59%	0.67%
2013	-1.88%	1.60%	2.42%	-0.81%	-1.06%
2014	-2.57%	1.78%	2.46%	-0.68%	-1.89%
2015	-2.27%	1.06%	3.41%	-2.35%	0.09%
2016	-3.77%	1.31%	1.21%	0.10%	-3.86%
2017	-1.70%	0.89%	3.58%	-2.69%	0.99%

Average Annual Growth Rates

1997-2017	-1.04%	1.82%	2.81%	**-0.99%**	**-0.05%**
2003-2017	-1.41%	1.86%	2.73%	**-0.86%**	**-0.54%**
2008-2017	-2.35%	1.44%	2.82%	**-1.38%**	**-0.97%**

Table 10

Impact of Component Costs on Kahn X Factor Results[1,2]

Year	GDPPI[3]	Operating Scale		Cost							Kahn X Factors by Cost Category					
				Capital					O&M	Total[8]						
		Retail Customers	Scale Index[4]	Rate of Return[5]	Rate Base[6]	Return on Rate Base	Depreciation and Amortization	Total[7]			Rate Base	Return on Rate Base	Depreciation and Amortization	Capital Cost	O&M Cost	Total Cost
	[A]		[B]	[C]	[D]	[E]=[C]+[D]	[F]	[G]	[H]	[I]	[A]+[B]-[D]	[A]+[B]-[E]	[A]+[B]-[F]	[A]+[B]-[G]	[A]+[B]-[H]	[A]+[B]-[I]
1997	1.71%	1.80%	2.31%	0.20%	2.75%	2.95%	5.21%	3.89%	3.77%	3.82%	1.27%	1.07%	-1.19%	0.13%	0.25%	0.19%
1998	1.08%	1.92%	1.86%	1.46%	1.51%	2.96%	2.21%	2.73%	4.32%	3.45%	1.43%	-0.02%	0.73%	0.21%	-1.38%	-0.51%
1999	1.42%	1.40%	1.30%	-5.68%	1.72%	-3.96%	3.55%	-1.16%	4.56%	1.06%	1.00%	6.68%	-0.82%	3.88%	-1.83%	1.67%
2000	2.25%	2.07%	1.07%	5.04%	2.44%	7.48%	4.51%	6.38%	5.73%	6.21%	0.88%	-4.16%	-1.19%	-3.06%	-2.41%	-2.89%
2001	2.26%	1.51%	1.03%	-2.97%	3.37%	0.40%	4.05%	1.86%	4.99%	3.16%	-0.08%	2.89%	-0.76%	1.43%	-1.70%	0.13%
2002	1.52%	1.40%	1.77%	-2.50%	4.42%	1.92%	3.04%	2.34%	2.66%	2.53%	-1.13%	1.36%	0.25%	0.94%	0.63%	0.76%
2003	1.98%	1.33%	1.88%	-2.59%	4.89%	2.29%	3.43%	2.73%	1.79%	2.43%	-1.02%	1.57%	0.43%	1.13%	2.08%	1.44%
2004	2.71%	1.45%	1.12%	-2.22%	4.71%	2.48%	1.96%	2.17%	3.83%	2.90%	-0.88%	1.34%	1.86%	1.66%	-0.01%	0.92%
2005	3.17%	1.51%	1.81%	-2.41%	4.57%	2.16%	4.68%	3.18%	4.60%	3.79%	0.41%	2.82%	0.30%	1.80%	0.38%	1.20%
2006	3.02%	0.20%	1.40%	-2.23%	4.88%	2.65%	4.08%	3.26%	4.92%	4.06%	-0.45%	1.77%	0.34%	1.16%	-0.49%	0.36%
2007	2.63%	1.40%	1.87%	-1.71%	6.14%	4.43%	6.29%	5.36%	6.63%	6.05%	-1.64%	0.07%	-1.79%	-0.85%	-2.13%	-1.55%
2008	1.91%	1.04%	1.46%	0.58%	8.07%	8.65%	2.41%	5.92%	3.27%	4.54%	-4.70%	-5.28%	0.97%	-2.55%	0.11%	-1.16%
2009	0.78%	0.60%	0.63%	-0.39%	9.65%	9.26%	7.45%	8.59%	0.66%	5.10%	-8.25%	-7.86%	-6.04%	-7.19%	0.75%	-3.69%
2010	1.22%	0.52%	1.03%	-0.35%	10.19%	9.84%	7.46%	8.84%	6.06%	7.85%	-7.94%	-7.58%	-5.20%	-6.59%	-3.81%	-5.59%
2011	2.04%	0.44%	1.09%	-1.48%	8.06%	6.58%	7.79%	7.17%	-0.26%	4.05%	-4.93%	-3.45%	-4.66%	-4.04%	3.39%	-0.92%
2012	1.82%	0.59%	0.61%	-2.22%	7.12%	4.90%	2.18%	3.72%	0.28%	2.36%	-4.69%	-2.47%	0.26%	-1.29%	2.16%	0.07%
2013	1.60%	0.78%	0.82%	-1.03%	6.54%	5.51%	4.58%	5.06%	2.96%	4.30%	-4.12%	-3.09%	-2.15%	-2.63%	-0.53%	-1.88%
2014	1.78%	0.81%	1.05%	-1.89%	6.86%	4.97%	5.13%	5.03%	6.13%	5.41%	-4.03%	-2.14%	-2.30%	-2.19%	-3.30%	-2.57%
2015	1.06%	1.02%	0.93%	1.10%	8.76%	9.86%	6.40%	8.52%	-2.61%	4.26%	-6.77%	-7.87%	-4.41%	-6.53%	4.60%	-2.27%
2016	1.31%	1.08%	0.21%	-3.54%	7.60%	4.06%	11.65%	7.24%	1.70%	5.29%	-6.08%	-2.55%	-10.13%	-5.72%	-0.18%	-3.77%
2017	0.89%	0.85%	0.08%	-0.69%	5.17%	4.48%	4.38%	4.43%	-0.82%	2.67%	-4.19%	-3.51%	-3.40%	-3.45%	1.79%	-1.70%
Average Annual Growth Rates																
1997-2017	1.82%	1.13%	1.21%	-1.21%	5.69%	4.47%	4.88%	4.63%	3.10%	4.06%	**-2.66%**	**-1.45%**	**-1.85%**	**-1.61%**	**-0.08%**	**-1.04%**
2003-2017	1.86%	0.91%	1.07%	-1.40%	6.88%	5.48%	5.32%	5.41%	2.61%	4.34%	**-3.95%**	**-2.55%**	**-2.40%**	**-2.49%**	**0.32%**	**-1.41%**
2008-2017	1.44%	0.77%	0.79%	-0.99%	7.80%	6.81%	5.94%	6.45%	1.74%	4.58%	**-5.57%**	**-4.58%**	**-3.71%**	**-4.22%**	**0.50%**	**-2.35%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]The annual growth rate of the U.S. Gross Domestic Product Price Index ("GDPPI").

[4] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 7. The formula becomes *growth* Scale [B] = 40.9% x [*growth* Retail Customers] + 23.2% x [*growth* Generation Capacity] + 7.9% x [*growth* Generation Volume] + 9.4% x [*growth* Transmission Line Miles] + 18.6% x [*growth* Ratcheted Peak Demand].

[5]The annual growth rate of an average of the Edison Electric Institute's "Rate Case Summary" ROE and the embedded cost of debt from FERC Form 1 data of a nationally representative sample of electric utilities.

[6]The growth rate of the average value of rate base at the start and end of the year.

[7]The annual growth rate in total capital cost does not equal the sum of the annual growth rates of return on rate base [E] and depreciation and amortization [F].

[8]The annual growth rate in total cost does not equal the sum of the annual growth rates of capital cost [G] and O&M cost [H].

than growth in their non-fuel O&M expenses. The rate base grew especially rapidly, and its growth has accelerated the most in recent years. Growth in the pro forma *return* on rate base was slowed by a decline in the *rate* of return. Growth in O&M expenses has decelerated in recent years.

Since VIEUs provide distributor services, their productivity growth can be slowed due to the same forces that affect distributor productivity growth. Recall from our discussion in Section 4.6 that these include the following:

- installation of AMI and other smart grid facilities, especially after 2007;[57]
- higher reliability and resiliency standards;
- increased DG penetration; and
- slowing growth in the number of gas customers served by combined gas and electric utilities, especially after 2007.

Sluggish growth in system use and the number of customers served, especially since 2007, has reduced opportunities to increase capacity utilization and incremental scale economies in the distribution sector of VIEUs, and also in their generation and transmission sectors.

There are additional reasons for slowing VIEU productivity growth which are unique to the generation and transmission sectors.

- VIEUs were increasingly encouraged to buy new power supplies rather than build new capacity. This further reduced their opportunities to realize scale economies.
- Some VIEUs made costly investments in equipment to control sulfur and other kinds of pollution from their fossil-fueled power plants. Growth in this capacity was especially brisk after 2007.[58]
- There was an uptick in generation capacity growth from 2001 to 2010 that was due in part to the diminishing ability of many utilities to meet demand growth from existing capacity. Several VIEUs (e.g., CLECO, Kansas City Power & Light, Public Service of Colorado, and

[57] AMI penetration has a statistically significant and positively-signed parameter estimate in our cost model.

[58] Percentage of generation capacity scrubbed has a statistically significant and positively-signed parameter estimate in our cost model.

Southwestern Electric Power) that increased generation capacity chose to build costly power plants fired by solid fossil fuels such as coal and petroleum coke.

- Pollution restrictions, renewable portfolio standards, investment tax incentives, and falling costs of generation from natural gas and renewable resources have spurred additions to gas-fired and renewables-powered generation capacity.[59] Gas-fired generation is cleaner than coal-fired generation and is more capable of offsetting fluctuations in generation from intermittent renewable resources. The benefits to the environment of investments in gas-fired and renewables-powered generation are not included in our productivity calculations.
- As is the case with power distribution, increased reliance on intermittent renewable resources for power supplies has not always translated into generation capacity savings.
- Growth in the generation volumes of many VIEUs (e.g., Indiana Michigan Power, Kansas Gas & Electric, Public Service of Oklahoma, Southern Indiana Gas & Electric, and Southwestern Public Service) has declined, reducing capacity utilization, due to slow native load growth, increased reliance on renewables-powered generation, and low prices in bulk power markets.
- Transmission capex was encouraged by the Energy Policy Act of 2005 and FERC regulatory policy. The North American Electric Reliability Corporation and regional transmission reliability organizations established new reliability standards. Several utilities (e.g., Minnesota Power, Northern States Power, Oklahoma Gas & Electric, and Southwestern Public Service) materially expanded transmission capacity in order to reach remote renewable resources or to improve the functioning of bulk power markets.
- As is true for energy distributors, when new G&T assets are acquired, long-run costs are often reduced by choosing assets with lengthy service lives and an ability to accommodate some future demand growth. However, these assets are to this extent more expensive and slow productivity growth in the short run. Traditional utility capital cost accounting involves historical plant valuations. These valuations magnify the revenue requirement impact of plant additions to the extent that an extensive share of older plant is highly depreciated.

[59] These additions included some conversions of coal-fired capacity to burn gas.

In summary, the slowing productivity growth of VIEUs has reflected an industry faced with slower demand growth but still needing to make sizable capital expenditures in order to install pollution controls, use cleaner-burning natural gas and intermittent renewable resources in generation, improve the functioning of bulk power markets, and modernize the grid. Important benefits of these investments are not captured by our scale indexes.

5.8 Implications for the HECO Companies

Some special considerations are pertinent in an application of our research results to the design of revenue adjustment indexes for HECO Companies. These Companies will have trackers for the cost of major plant additions. However, major plant additions typically account for less than half of the Companies' capex. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes. There may be markdowns on the major plant additions that are otherwise eligible for tracker treatment. Moreover, the revenue adjustment indexes will not include scale escalators.

5.9 X Factor Conclusions

Our empirical cost research for the HECO Companies suggests that a revenue adjustment index that uses the GDPPI as the sole inflation measure must typically have a negative X factor if it is to be compensatory for a VIEU. One reason is that the GDPPI tends to understate utility input price inflation. Another is that VIEU productivity growth has slowed.

Appendix

Details of PEG's Empirical Research

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

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.

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. Here is the general formula for these indexes:

$$\ln\left(Input\,Prices_t \big/ Input\,Prices_{t-1} \right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot \ln\left(W_{j,t} \big/ W_{j,t-1} \right). \qquad [A1]$$

Here, in each year *t*,

$Input\,Prices_t$ = Input price index

$W_{j,t}$ = Price sub-index 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 sub-index 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

We explained in Section 3.2 above that there are monetary approaches to the calculation of capital cost that permit its decomposition into a capital quantity index and a capital price index.

$CK = WK \cdot XK.$

In our input price and econometric cost research two monetary approaches were chosen to measure the capital cost and input price indexes of each sampled utility.

Geometric Decay

In our econometric cost research a GD capital cost specification was employed. PEG took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity index in this year were based on the net value of plant as reported in the FERC Form 1. We estimated the quantity of 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 Electric Utility Construction for total plant – all steam generation.[60]

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

$$XK_t = (1 - d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \quad [A2]$$

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

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \quad [A3]$$

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

COS

A COS capital cost specification was used to calculate the VIEU input price indexes that we used in our inflation differential calculation. Our COS formulas are complex but reflect how capital cost is typically calculated in U.S. utility regulation.

For each utility in each year t of the sample period we define the following terms.

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

CK	Total non-tax cost of capital
CKR	Return on net plant value
CKD	Depreciation expenses
VKA_{t-s}	Gross value of plant installed in year t-s
WKA_{t-s}	Market cost per unit of plant constructed in year t-s
XKA_{t-s}	Quantity of plant added in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$
sck_{t-s}	Share of vintage *t-s* assets in total capital cost
N	Average service life of plant
r_t	Rate of return on net plant value
WK_{t-s}	Price of capital in year *t-s*
WK	Summary capital price index
XK	Summary capital quantity index

The non-tax cost of capital is the sum of depreciation and the pro forma return on net plant value. Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$CK_t = CKD_t + CKR_t$$

$$= \sum_{s=0}^{N-1}\left(\frac{1}{N}\right)\cdot VKA_{t-s} + r\cdot\sum_{s=0}^{N-1}\left(VKA_{t-s} - s\cdot\frac{1}{N}\cdot VKA_{t-s}\right)$$

$$= \sum_{s=0}^{N-1}\left(\frac{1}{N}\right)\cdot WKA_{t-s}\cdot XKA_{t-s} + \sum_{s=0}^{N-1} r\cdot\left(1 - s\cdot\frac{1}{N}\right)\cdot WKA_{t-s}\cdot XKA_{t-s}$$

$$= \sum_{s=0}^{N-1}\left[\frac{1}{N} + r_t\cdot\left(1 - s\cdot\frac{1}{N}\right)\right]\cdot WKA_{t-s}\cdot XKA_{t-s}$$

$$= \sum_{s=0}^{N-1} WK_{t-s}\cdot XKA_{t-s} \qquad [A4]$$

Here the price of assets dating to year *t-s* is given by

$$WK_{t-s} = \left[\frac{1}{N} + r_t\cdot\left(1 - s\cdot\frac{1}{N}\right)\right]\cdot WKA_{t-s}. \qquad [A5]$$

It can be seen that capital cost is decomposed into the costs attributable to plant dating to numerous past years. The vintage of the annual capital price and quantity is older the higher is the value of s. Due to depreciation and the historical valuation of plant, WK_{t-s} is lower the higher is the value of s.

From calculus, we know that the growth rate of capital cost ("ΔCK") is a cost share weighted average of the growth rates of capital costs of various vintages ("ΔCK_{t-s}"). Furthermore,

$$\begin{aligned}\Delta CK &= \sum_{s=0}^{N-1} sck_{t-s} \cdot \Delta CK_{t-s} \\ &= \sum_{s=0}^{N-1} sck_{t-s} \cdot (\Delta WK_{t-s} + \Delta XKA_{t-s}) \\ &= \sum_{s=0}^{N-1} sck_{t-s} \cdot \Delta WK_{t-s} + \sum_{s=0}^{N-1} sck_{t-s} \cdot XKA_{t-s} \\ &= \Delta WK + \Delta XK \qquad \text{[A6]}\end{aligned}$$

Here ΔWK, the growth rate of the capital price, is a cost-share weighted average of the growth rates in the capital service prices for each of the N vintages. It can be seen that market construction costs and the rate of return on net plant value play key roles in capital price index growth.

ΔXK, the growth rate of the capital quantity, is a cost-share weighted average of the growth of the capital quantity indexes for each of the N vintages. Weights will tend to be heavier on the quantities of newer assets since these assets are less depreciated and valued in more recent dollars. In a period of rapid system modernization, there would be higher growth rates in the quantities of vintages that tend to have higher weights and less growth in the quantities of vintages that tend to have lower weights. Capital quantity growth would then accelerate.

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Response to Staff Discussion on the Revenue Cap Index

8 March 2019

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Table of Contents

1. Staff's Revenue Cap Index Proposal

The HECO Companies currently operate under revenue cap mechanisms that address operation and maintenance ("O&M") expenses and capital cost separately. Each company is also subject to a Rate Adjustment Mechanism ("RAM") cap with the following general formula:

growth Allowed Base Revenue = growth GDPPI. [1]

GDPPI is the U.S. government's gross domestic product price index. Supplemental base rate revenue is available to each Company via a Major Project Interim Recovery ("MPIR") tracker and other trackers. However, the Companies have tended to underearn since the RAM caps were instituted. This suggests that the RAM caps have been undercompensatory for the costs to which they apply, which include those for labor, materials, services, and many kinds of capital expenditures ("capex").

Staff proposes a new approach to performance-based regulation in its February 7 report.[1] Allowed base revenue would be escalated by a revenue cap index of the following general form:

Revenue Cap Index = Inflation – (*X Factor+ Consumer Dividend Factor*) *+ Z Factor*. [2]

Supplemental base rate revenue would once again potentially be available to each Company via an MPIR tracker and other trackers.

Staff notes on p. 26 of its report that in an attrition relief mechanism ("ARM")

> The inflation measure is often a macroeconomic index such as the Gross Domestic Product Price Index (GDPPI); however, custom indexes of utility price inflation are sometimes used in ARM design. The appropriate inflation measure will be an important consideration in Phase 2.
>
> The productivity, or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of utilities. Phase 2 will need to determine the appropriate value for X; however, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range (e.g. zero to 1 percent).

[1] Hawaii Public Utilities Commission Staff, *Staff Proposal for Updated Performance-Based Regulations*, 7 February 2019.

2. PEG Commentary

The revenue cap index would be vitally important to the financial health of the HECO Companies and the viability of Staff's proposed plan. It is therefore worthwhile to review available evidence on revenue cap index design and to add some supplementary evidence.

Basic Results of Index Logic

PEG provided extensive evidence on revenue cap index design in their report that was attached as Exhibit 1 of the Company's January 4th brief. We explained that growth in the cost of a utility is theoretically the sum of its input price inflation and growth in its operating scale less growth in its productivity.

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Scale}. \quad [3]$$

While the number of customers is a sensible scale variable for gas or electric power distribution, a multidimensional scale index is more appropriate for a vertically integrated electric utility ("VIEU") like HECO.

This result provides the basis for the following general revenue cap index:

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility}. \quad [4a]$$

Here the X factor has the formula

$$X = \overline{\textit{trend Productivity}}^{Industry} + \textit{Stretch} \quad [4b]$$

where $\overline{\textit{trend Productivity}}^{Industry}$ is the base productivity trend of a peer group (or industry) and *Stretch* is the stretch factor.

The appropriate formula for X is different when a macroeconomic inflation measure such as the GDPPI is used. The GDPPI measures inflation in the *final* goods and services of the U.S. *economy* and not the *input price* inflation of *utilities*. GDPPI growth is slowed by the multifactor productivity ("MFP") growth of the U.S. economy, and this has been brisk for many years. GDPPI growth may also differ from utility input price growth due to the different input mix of the economy. Reflecting these considerations, when the GDPPI is the inflation measure, the X factor formula that has been most commonly used in U.S. ARMs that have been designed using cost trend research is

$$X = [\ (\overline{\textit{trend Productivity}}^{Industry} - \overline{\textit{trend Productivity}}^{Economy})$$
$$+ (\overline{\textit{trend Input Prices}}^{Economy} - \overline{\textit{trend Input Prices}}^{Industry}) + \textit{Stretch}\ ]. \quad [4c]$$

Here the first term in parentheses is called the "productivity differential". The second term in parentheses is called the "input price differential". An early discussion of this logic was set forth in Dr. Lowry's 1999 testimony in support of multiyear rate plans for the HECO Companies.[2]

Salient Precedents

Revenue Cap Indexes

Table 1 provides a summary of revenue cap indexes that are based on cost trend research and have been approved by North American regulators. It can be seen that the majority have included a scale escalator.

Table 2 documents instances in which regulators have reduced X by the MFP trend of the national economy when the inflation measure used in a rate or revenue cap index was macroeconomic. The table includes all known instances of this adjustment for energy utilities and a representative sampling of the analogous adjustments in PBR plans for telecom utilities. There are many more instances of productivity differentials in telecommunications utility X factors.

Base Productivity Trends and Stretch Factors

Table 3 and Figures 1 and 2 provide summaries of the base productivity trends, stretch factors, and X factors in energy utility rate and revenue cap indexes that have been informed by cost trend research and approved by North American regulators. The following results are notable.

- Base productivity trends acknowledged by regulators have slowed. The average of the acknowledged base productivity trends in current plans is 0.23%.
- Stretch factors have also trended downward over time. The average of the approved stretch factors in current plans is 0.21%.
- X factors have also trended downward over time. The average X factor in current plans is 0.09%. This average is raised considerably by the fact that many current plans are in Canada. Productivity differentials are rare in Canadian X factor calculations for two reasons. One is that industry-specific inflation measures are more common in rate and revenue cap indexes. Another is that the MFP trend of the economy has been much slower in Canada than in the U.S., as shown in Table 4. The average value of the X factor in current *U.S.* plans is -1.40%.

It should also be noted that many multiyear rate plans approved for energy utilities in Canada have provisions for supplemental capital revenue. PEG discussed these precedents at length in their January report.

[2] See the Testimony of Mark N. Lowry in Hawaii PUC Docket 1999-0396, Exhibit T-2, p. 16, lines 11-22. See also Lowry & Kaufmann, "Performance-Based Regulation of Utilities", *Energy Law Journal*, 2002.

Table 1

Summary of Approved Revenue Cap Indexes Designed Using Cost Trend Research[1]

Jurisdiction	Utility	Applicable Services	Plan Term	Escalator(s)
California	Southern California Gas	Gas Distribution	1997-2002	Customers
British Columbia	BC Gas[2]	Gas Distribution	1998-2000	Customers, Service Line Additions, etc.
California	Southern California Edison	Power Distribution	2002-2003	Customers
Quebec	Gazifere	Gas Distribution	2006-2010	Customers
Vermont	Vermont Gas Systems	Gas Distribution	2006-2009, extended to 2015	Customers
Ontario	Enbridge Gas	Gas Distribution	2008-2012	Customers
Vermont	Central Vermont Public Service	Power Distribution	2009-2011, extended to 2013	None
Vermont	Green Mountain Power	Power Distribution	2010-2013	None
Quebec	Gazifere	Gas Distribution	2011-2015	Customers
Alberta	All Distributors	Gas Distribution	2013-2017	Customers
British Columbia	FortisBC	Bundled Power Service	2014-2019	Customers
British Columbia	FortisBC Energy[2]	Gas Distribution	2014-2019	Customers, Service Line Additions
Alberta	All Distributors	Gas Distribution	2018-2022	Customers
Massachusetts	Eversource Energy	Power Distribution	2018-2023	None
Québec	Hydro-Québec	Power Distribution	2018-2022	Customers

[1] Shaded plans have expired.

[2] There are separate revenue cap indexes for O&M expenses and various kinds of capex in these plans that in some instances have separate escalators.

Table 2

Precedents for Productivity Differentials in the Calibration of Approved X Factors

Jurisdiction	Company	Plan Term	Services Covered	Inflation Measure	Case Reference
Connecticut	SNET	1996-2001	Telecom	GDPPI	Docket 95-03-01
Illinois	Ameritech	1995-2002	Telecom	GDPPI	Case 92-0048/93-0239
Massachusetts	NYNEX	1995-2001	Telecom	GDPPI	D.P.U. 94-50
Massachusetts	Eversource Energy	2018-2022	Power distribution	GDPPI	DPU 17-05; November 2017
Massachusetts	Bay State Gas	2006-2015, terminated in 2009	Gas distribution	GDPPI	Docket DTE 05-27
Massachusetts	Boston Gas (I)	1997-2001	Gas distribution	GDPPI	Docket D.P.U. 96-50-C (Phase I); May 1997
Massachusetts	Boston Gas (II)	2004-2013, Terminated in 2010	Gas distribution	GDPPI	Docket DTE 03-40
New York	NYNEX	1995-1999	Telecom	GDPPI	Case 92-G-0665
US National	LECs	1997-2000	Telecom	GDPPI	Docket 97-159
Canada National	BC Tel, Bell Canada, Island Tel, MTT, MTS, NB Tel, TELUS	1998-2001	Telecom	GDPPI	CRTC 97-9
Ontario, Canada	Union Gas	2001-2003	Gas distribution	GDP IPI Canada	RP-1999-0017; July 2001
Australia - Northern Territory	Power & Water	2009-2014	Power transmission & distribution	CPI Australia	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Jamaica	Jamaica Public Service	2015-2019	Bundled Power Service	CPI Jamaica adjusted for US inflation	Jamaica Public Service Company Limited Tariff Review for Period 2014-2019 Determination Notice
New Zealand	All	2004-2009	Power distribution	CPI New Zealand	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
New Zealand	All	2010-2015	Power distribution	CPI New Zealand	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009

Table 3

Summary of Base Productivity Trend, Stretch Factor, and X Factor Decisions in North American PBR Proceedings[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Oil pipelines	All U.S.	United States	1995-2001	Price Cap	PPI-Finished Goods	NA	NA	1.00%
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Oil pipelines	All U.S.	United States	2001-2006	Price Cap	PPI-Finished Goods	NA	NA	0.00%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Terasen Gas	British Columbia	2004-2009	Revenue Cap	CPI	NA	NA	63% x Inflation (Average)
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDPIPI	NA	NA	1.00%
Oil pipelines	All U.S.	United States	2006-2011	Price Cap	PPI-Finished Goods	NA	NA	-1.30%
Power Distribution	Nstar	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 3 (Continued)

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Oil pipelines	All U.S.	United States	2011-2016	Price Cap	PPI-Finished Goods	NA	NA	-2.65%
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2020	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%
Oil pipelines	All U.S.	United States	2016-2021	Price Cap	PPI-Finished Goods	NA	NA	-1.23%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%
Power Distribution	Hydro-Québec	Québec	2018-2022	Revenue Cap	Industry-specific	NA	0.00%	0.30%
Power Distribution	Eversource Energy	Massachusetts	2018-2023	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.56%
Gas Distribution	Amalco	Ontario	2019-2023	Price Cap	GDPPI	0.00%	0.30%	0.30%

Averages*	**All Current and Expired Plans**	**0.59%**	**0.38%**	**0.74%**
	All Current Plans	**0.23%**	**0.21%**	**0.09%**

*Averages exclude X factors that are percentages of inflation.

[1] Shaded plans have expired.

[2] Some approved X factors are not explicitly constructed from such components as a base productivity trend and a stretch factor. Many of these are the product of settlements.

[3] X factors may not be the sum of the acknowledged productivity trend and the stretch factor, where these are itemized, for the following reasons: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism or (2) the X factor may incorporate additional adjustments to account for special business conditions.

Figure 1

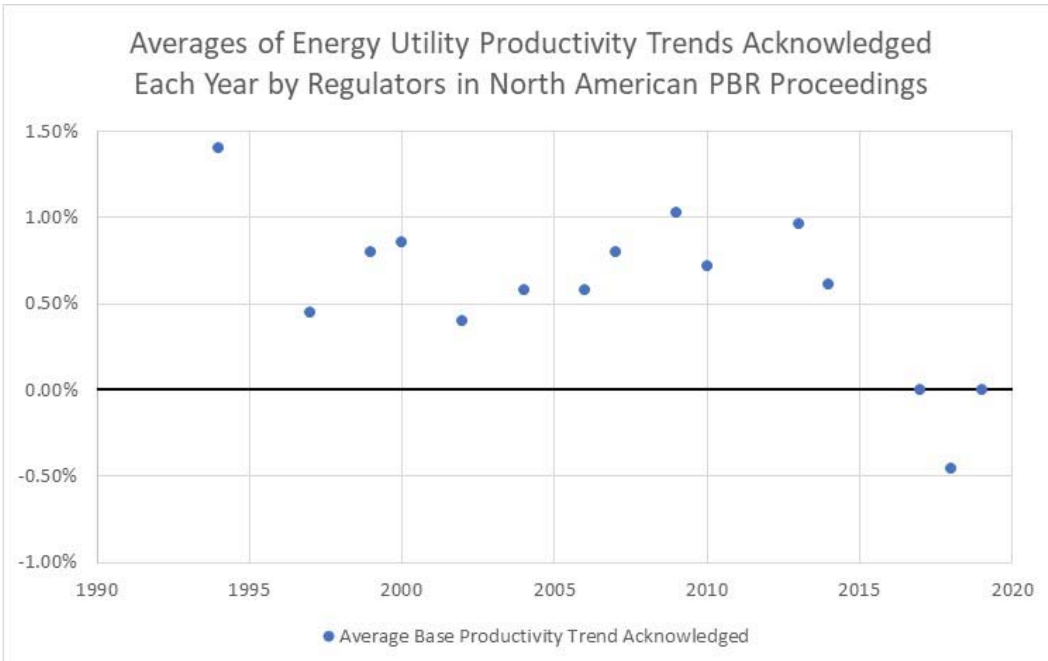

Figure 2

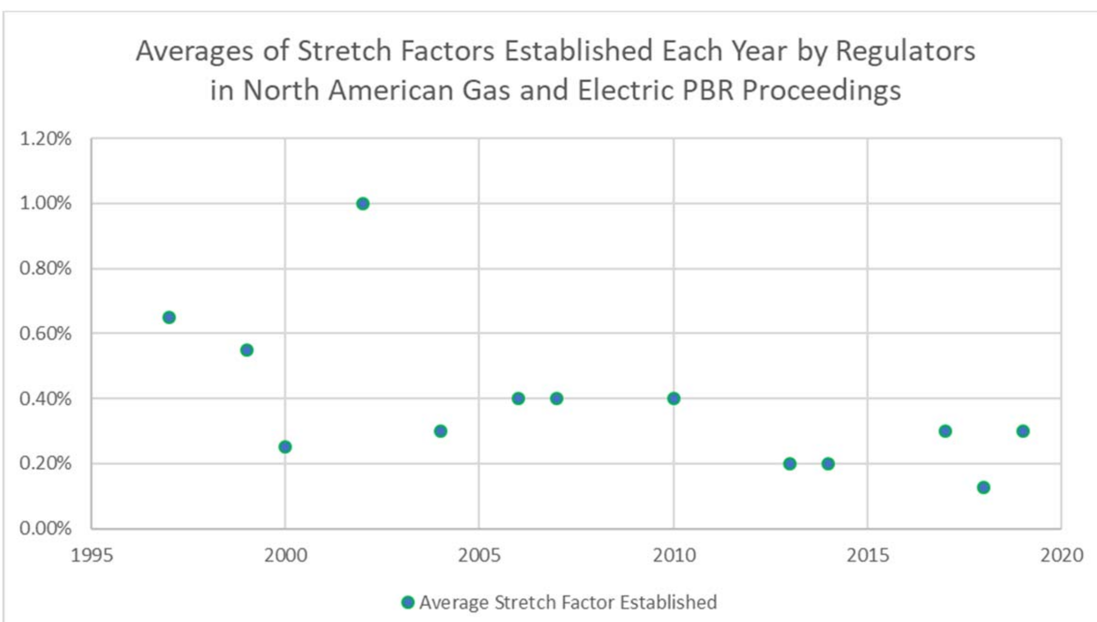

Table 4

MFP Trends of the U.S. and Canadian Economies

Year	United States		Canada	
	MFP[1]	Growth Rate	MFP[2]	Growth Rate
1987	82.53		97.40	
1988	83.28	0.90%	97.52	0.13%
1989	83.49	0.25%	96.66	-0.89%
1990	83.93	0.53%	94.86	-1.87%
1991	83.36	-0.69%	92.27	-2.77%
1992	86.01	3.14%	92.94	0.72%
1993	85.49	-0.61%	93.93	1.06%
1994	85.89	0.47%	96.42	2.61%
1995	85.65	-0.28%	96.75	0.34%
1996	86.84	1.38%	95.77	-1.01%
1997	87.82	1.12%	97.02	1.29%
1998	89.13	1.48%	97.61	0.61%
1999	90.84	1.90%	99.90	2.32%
2000	92.14	1.43%	102.09	2.18%
2001	92.56	0.45%	102.01	-0.08%
2002	94.44	2.02%	103.08	1.04%
2003	96.63	2.29%	102.32	-0.74%
2004	99.18	2.61%	101.95	-0.36%
2005	100.71	1.53%	101.96	0.01%
2006	101.07	0.35%	101.13	-0.82%
2007	101.46	0.39%	100.00	-1.13%
2008	100.26	-1.19%	97.71	-2.32%
2009	100.00	-0.26%	95.20	-2.60%
2010	103.31	3.25%	96.91	1.78%
2011	103.38	0.07%	98.36	1.49%
2012	104.09	0.69%	97.77	-0.60%
2013	104.52	0.41%	98.43	0.67%
2014	105.43	0.87%	99.85	1.43%
2015	106.42	0.93%	98.86	-1.00%
2016	105.93	-0.46%	98.94	0.08%
2017	106.73	0.76%	NA	NA
Average Annual Growth Rates				
1988-2016		**0.86%**		**0.05%**
1997-2016		**0.99%**		**0.16%**

[1] Bureau of Labor Statistics, March 21, 2018, Office of Productivity and Technology, Division of Major Sector Productivity

[2] Statistics Canada. Table 36-10-0208-01, Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by industry

Other Notable Precedents

Negative X factors have also been approved by regulators in Britain and Australia. In both countries, the ARMs of multiyear rate plans have a hybrid design in which an inflation-X formula is used but X reflects multiyear forecasts of cost and inflation. One example is found in the 2006 British Transmission Price Control Review Final Proposals where Ofgem approved an RPI+2 price control for electric transmission utilities "to ensure that revenues, and associated cash flows are aligned more closely to the rising trend of costs resulting from the substantial increase in investment envisaged over the 5 year period."[3]

The Brattle Group's report, presented as Exhibit 2 to the HECO Companies' January 4th brief in this proceeding, outlined several recent revenue cap precedents for Australian and British power distributors.[4] The authors reported that the current MRPs for all five power distributors in Victoria, Australia allowed annual increases in authorized revenues in excess of inflation, and that these averaged 1.8%. The Brattle Group also found that in the most recently completed round of MRPs for British power distributors, 13 of 14 distributors had allowed revenue growth in excess of inflation, and real revenue increases for British power distributors averaged nearly 6% annually.

The Brattle Group's report also discussed the recent revenue requirement trends of the three large California energy utilities. They found that for the 2007-2018 period, authorized base revenues for these utilities increased 2.5% more rapidly than the growth in the GDPPI on average.[5]

Application to HECO

Introduction

To develop a revenue cap index for the HECO Companies that uses GDPPI as the inflation measure, a rigorous and thorough approach would be to use the latest available data (e.g., through 2017) from the Federal Energy Regulatory Commission ("FERC") and other reputable sources to 1) develop a scale index using econometric research on VIEU cost to identify scale variables and their cost elasticities and 2) calculate the average productivity and inflation differentials of the sampled utilities. A stretch factor (e.g., 0.20) could be added to X to share with customers the benefit of accelerated productivity growth that is expected under the terms of the plan.

An X factor could instead be calculated using a simpler "Kahn Method" exercise. In an application to HECO, one would calculate trends in the cost of base rate inputs of a sample of VIEUs using FERC Form 1 data and traditional cost accounting and then solve for the value of X which would have caused the trend in VIEU cost to equal the trend in a revenue cap index on average when GDPPI is the inflation measure. This analysis would exclude costs that are likely to be addressed by trackers and

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[3] Ofgem, *Transmission Price Control Review Final Proposals*, December 2006, p. 7.

[4] Toby Brown and William Zarakas (2019), "Improving the PBR Framework in Hawai'I Addressing the Risk of 'Capex Bias'", p. 9.

[5] Toby Brown and William Zarakas (2019), "Improving the PBR Framework in Hawai'I Addressing the Risk of 'Capex Bias'", p. 10.

riders in the Companies' regulatory systems. The X factor resulting from such a calculation reflects the input price and productivity differentials of utilities.

The FERC has approved three consecutive inflation-X multi-year rate plans for interstate oil pipelines using the Kahn method and pipeline industry data. The current oil pipeline index escalates prices by the Producer Price Index for Finished Goods plus 1.23%, implicitly indicating an X factor of -1.23%. The prior oil pipeline index escalated prices by the Producer Price Index for Finished Goods plus 2.65%, indicating an X factor value of -2.65%.

One complication with such empirical research in an application to the HECO Companies is that they are subject to MPIR trackers. These have chiefly been used to date for costs of new renewable-related generation capacity. One way to finesse this complication is by not escalating the revenue requirement for growth in generation capacity or volume. At the extreme, the scale index could be removed from the RAM cap formula in its entirety.

PEG Empirical Research

PEG has undertaken three kinds of empirical research to consider alternative RAM caps for the HECO Companies. All three tasks used a sample of good data for 44 major investor-owned American VIEUs. Data on the cost and operating scale of these utilities were obtained from their FERC Form 1 and U.S. Energy Information Administration filings.

Costs were excluded from the research which were not pertinent to the design of a RAM cap for the HECO Companies. Most exclusions were made because the Companies do not incur these costs or because these costs will likely be addressed using trackers. The excluded costs included those for the following inputs:

- Generation fuels, purchased power, and other power supply expenses
- Non-fuel nuclear and hydroelectric generation inputs
- Pensions and benefits
- Load dispatching, transmission by others, and miscellaneous transmission expenses
- Customer service and information inputs.[6]

PEG's first task using these data was to develop an appropriate scale index. We estimated the parameters of an econometric model of the cost of VIEU base rate inputs. PEG identified seven business condition variables with statistically significant and plausibly-signed parameter estimates.[7] These include the following four scale variables:

- Generation capacity
- Generation volume

[6] For many utilities, this cost category is dominated by DSM program expenses.

[7] The model also contained a trend variable with a slightly positive parameter estimate.

- Transmission line miles
- Number of retail customers.

Since the values of cost and all business condition variables in the cost model were logged, the parameter estimates for these scale variables are also estimates of the elasticity of cost with respect to these variables.

The econometric elasticity estimates were used to calculate the weights for a scale index. The largest weight by far was the 63.3% weight assigned to the number of customers served. Generation volume had a weight around 13.2% whereas generation capacity had a 12.9% weight and transmission line miles had a 10.6% weight.

We then postulated a hypothetical generic revenue cap index with the following form:

$$growth\ Allowed\ Base\ Revenue^{Utility} = growth\ GDPPI - X + growth\ Scale^{Utility}. \quad [5]$$

The scale index used the four scale variables and elasticity weights discussed above. We 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 calculated the value of X that would cause the trends in the costs of the sampled VIEUs to equal the trends in the hypothetical revenue cap indexes on average over the sample period. The full sample period considered was the twenty-one-year 1997-2017 period. We also considered the results for shorter and more recent periods.

Updated results of this exercise are reported Table 5. For all sample periods considered, it can be seen that the average annual growth in cost was considerably more rapid than the average annual growth in the GDPPI. The average annual growth in the scale index was not large enough to close the gap. Thus, the X factor must be negative if the hypothetical revenue cap indexes are to track historical VIEU costs of base rate inputs on average. Using the scale index, the Kahn X factor was -1.21% for the full 1997-2017 sample period and - 1.48% for the more recent 2002-2017 sample period. Similar values for X were obtained using the number of customers as the scale escalator in the hypothetical revenue cap indexes.

Table 6 decomposes the Kahn X factor results to show which components of cost are driving the negative values. It can be seen that growth in capital cost has been much more rapid than the growth in O&M expenses. One reason is the marked cost impact of replacing old assets, which are valued in historical dollars and highly depreciated at the time of their replacement.

Table 5

U.S. VIEU Kahn X Factor Calculations[1,2]

Year	Operating Scale							Kahn X Factors	
	Retail Customers	Generation Capacity	Generation Volume	Transmission Line Miles	Scale Index[3]	Inflation[4]	Total Cost	Using Scale Index	Using Customers
	[A]	[B]	[C]	[D]	[E]	[G]	[F]	[E+G-F]	[A+G-F]
1997	1.80%	-0.29%	3.70%	0.19%	1.61%	1.71%	8.21%	-4.90%	-4.71%
1998	1.92%	0.54%	7.41%	0.45%	2.31%	1.08%	3.30%	0.09%	-0.30%
1999	1.40%	-2.04%	1.32%	0.32%	0.83%	1.42%	-3.19%	5.45%	6.01%
2000	2.07%	-1.09%	4.58%	-1.99%	1.56%	2.25%	6.21%	-2.40%	-1.90%
2001	1.51%	2.05%	-1.95%	0.02%	0.96%	2.26%	3.16%	0.06%	0.61%
2002	1.40%	6.72%	-1.46%	0.11%	1.57%	1.52%	2.53%	0.56%	0.39%
2003	1.33%	3.34%	-0.47%	0.30%	1.25%	1.98%	2.43%	0.80%	0.89%
2004	1.45%	0.76%	0.35%	-0.48%	1.01%	2.71%	2.90%	0.82%	1.26%
2005	1.51%	4.07%	2.40%	-0.30%	1.77%	3.17%	3.79%	1.15%	0.89%
2006	0.20%	4.49%	-0.54%	-1.61%	0.46%	3.02%	4.01%	-0.53%	-0.79%
2007	1.40%	2.10%	5.19%	1.90%	2.04%	2.63%	6.02%	-1.35%	-1.99%
2008	1.04%	3.10%	0.19%	0.68%	1.15%	1.91%	4.54%	-1.47%	-1.59%
2009	0.60%	1.32%	-9.33%	1.24%	-0.55%	0.78%	5.09%	-4.85%	-3.70%
2010	0.52%	2.96%	9.30%	0.85%	2.03%	1.22%	7.85%	-4.60%	-6.11%
2011	0.44%	0.61%	-2.82%	0.60%	0.05%	2.04%	4.04%	-1.95%	-1.56%
2012	0.59%	2.02%	-1.25%	1.21%	0.60%	1.82%	2.36%	0.06%	0.05%
2013	0.78%	0.11%	2.97%	-0.25%	0.87%	1.60%	4.31%	-1.83%	-1.92%
2014	0.81%	2.33%	1.92%	1.67%	1.25%	1.78%	5.40%	-2.38%	-2.81%
2015	1.02%	-0.48%	-4.25%	0.58%	0.08%	1.06%	4.26%	-3.12%	-2.19%
2016	1.08%	-0.56%	-1.65%	1.47%	0.55%	1.31%	5.28%	-3.42%	-2.89%
2017	0.85%	-0.06%	-1.63%	-0.16%	0.30%	0.89%	2.68%	-1.49%	-0.94%
Average Annual Growth Rates									
1997-2017	1.13%	1.52%	0.67%	0.32%	1.03%	1.82%	4.06%	**-1.21%**	**-1.11%**
2002-2017	0.94%	2.05%	-0.07%	0.49%	0.90%	1.84%	4.22%	**-1.48%**	**-1.44%**
2007-2017	0.83%	1.22%	-0.12%	0.89%	0.76%	1.55%	4.71%	**-2.40%**	**-2.33%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 44 vertically intergrated electric utilities.

[3]Growth in the scale index is a cost-elasticity-weighted average of growth in customers, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 1 of *Regulatory Reform for the Hawaiian Electric Companies* Exhibit 1-2018-0088. The formula becomes *growth* Scale [E] = 63.3% x [A] + 12.9% x [B] + 13.2% x [C] + 10.6% x [D].

[4]The annual growth rate of the U.S. Gross Domestic Product Price Index (GDPPI)

Our third task was to decompose the X factor. For each VIEU in the sample we calculated an index of the trends in prices of base rate inputs. In these calculations, we used a formula designed to mimic the traditional cost of service treatment of capital cost. We used these indexes to calculate the difference between the GDPPI and industry input price trends.

EXHIBIT D4
DOCKET NO. 2018-0088
PAGE 16 OF 18

EXHIBIT B
DOCKET NO. 2018-0088
PAGE 16 OF 18

Table 6

Decomposition of U.S. VIEU Kahn X Factor Calculations by Cost Category[1,2]

Year	Inflation[3]	Operating Scale		Capital Cost					O&M Cost	Total Cost[8]	Kahn X Factors by Cost Category					
		Retail Customers	Scale Index[4]	Rate of Return[5]	Rate Base[6]	Return on Rate Base	Depreciation and Amortization	Total[7]			Rate Base	Return on Rate Base	Depreciation and Amortization	Capital Cost	O&M Cost	Total Cost
	[A]		[B]	[C]	[D]	[E]=[C]+[D]	[F]	[G]	[H]	[I]	[A]+[B]-[D]	[A]+[B]-[E]	[A]+[B]-[F]	[A]+[B]-[G]	[A]+[B]-[H]	[A]+[B]-[I]
1997	1.71%	1.80%	1.61%	0.20%	9.31%	9.51%	5.21%	9.34%	3.77%	8.21%	-5.99%	-6.19%	-1.89%	-6.02%	-0.45%	-4.90%
1998	1.08%	1.92%	2.31%	1.46%	1.46%	2.92%	2.21%	2.67%	4.32%	3.30%	1.94%	0.48%	1.18%	0.72%	-0.93%	0.09%
1999	1.42%	1.40%	0.83%	-5.68%	-4.79%	-10.48%	3.55%	-6.55%	4.56%	-3.19%	7.05%	12.73%	-1.29%	8.81%	-2.30%	5.45%
2000	2.25%	2.07%	1.56%	5.04%	2.44%	7.48%	4.51%	6.38%	5.73%	6.21%	1.37%	-3.67%	-0.71%	-2.57%	-1.92%	-2.40%
2001	2.26%	1.51%	0.96%	-2.96%	3.37%	0.40%	4.05%	1.86%	4.99%	3.16%	-0.15%	2.82%	-0.83%	1.36%	-1.77%	0.06%
2002	1.52%	1.40%	1.57%	-2.50%	4.42%	1.92%	3.04%	2.34%	2.66%	2.53%	-1.33%	1.17%	0.05%	0.75%	0.44%	0.56%
2003	1.98%	1.33%	1.25%	-2.59%	4.89%	2.29%	3.43%	2.73%	1.79%	2.43%	-1.66%	0.93%	-0.21%	0.49%	1.44%	0.80%
2004	2.71%	1.45%	1.01%	-2.22%	4.71%	2.48%	1.96%	2.17%	3.83%	2.90%	-0.99%	1.24%	1.76%	1.56%	-0.11%	0.82%
2005	3.17%	1.51%	1.77%	-2.41%	4.57%	2.16%	4.68%	3.18%	4.60%	3.79%	0.37%	2.77%	0.26%	1.76%	0.34%	1.15%
2006	3.02%	0.20%	0.46%	-2.23%	4.88%	2.65%	4.08%	3.26%	4.80%	4.01%	-1.39%	0.83%	-0.60%	0.22%	-1.31%	-0.53%
2007	2.63%	1.40%	2.04%	-1.71%	6.14%	4.43%	6.29%	5.35%	6.57%	6.02%	-1.47%	0.25%	-1.61%	-0.68%	-1.90%	-1.35%
2008	1.91%	1.04%	1.15%	0.58%	8.07%	8.65%	2.41%	5.92%	3.27%	4.54%	-5.01%	-5.58%	0.66%	-2.85%	-0.20%	-1.47%
2009	0.78%	0.60%	-0.55%	-0.39%	9.65%	9.26%	7.45%	8.59%	0.62%	5.09%	-9.42%	-9.03%	-7.21%	-8.36%	-0.38%	-4.85%
2010	1.22%	0.52%	2.03%	-0.35%	10.19%	9.84%	7.46%	8.84%	6.06%	7.85%	-6.94%	-6.59%	-4.20%	-5.59%	-2.81%	-4.60%
2011	2.04%	0.44%	0.05%	-1.48%	8.06%	6.58%	7.79%	7.17%	-0.28%	4.04%	-5.97%	-4.49%	-5.70%	-5.08%	2.37%	-1.95%
2012	1.82%	0.59%	0.60%	-2.22%	7.12%	4.90%	2.18%	3.72%	0.28%	2.36%	-4.70%	-2.48%	0.24%	-1.30%	2.14%	0.06%
2013	1.60%	0.78%	0.87%	-1.03%	6.54%	5.51%	4.58%	5.06%	2.97%	4.31%	-4.07%	-3.04%	-2.10%	-2.58%	-0.49%	-1.83%
2014	1.78%	0.81%	1.25%	-1.89%	6.86%	4.97%	5.13%	5.03%	6.12%	5.40%	-3.83%	-1.95%	-2.11%	-2.00%	-3.09%	-2.38%
2015	1.06%	1.02%	0.08%	1.10%	8.76%	9.86%	6.40%	8.51%	-2.61%	4.26%	-7.62%	-8.72%	-5.26%	-7.37%	3.75%	-3.12%
2016	1.31%	1.08%	0.55%	-3.54%	7.60%	4.06%	11.65%	7.24%	1.69%	5.28%	-5.74%	-2.20%	-9.79%	-5.38%	0.17%	-3.42%
2017	0.89%	0.85%	0.30%	-0.69%	5.17%	4.48%	4.38%	4.43%	-0.79%	2.68%	-3.98%	-3.29%	-3.19%	-3.24%	1.98%	-1.49%
Average Annual Growth Rates																
1997-2017	1.82%	1.13%	1.03%	-1.21%	5.69%	4.47%	4.88%	4.63%	3.09%	4.06%	**-2.83%**	**-1.62%**	**-2.03%**	**-1.78%**	**-0.24%**	**-1.21%**
2002-2017	1.84%	0.94%	0.90%	-1.47%	6.73%	5.25%	5.18%	5.22%	2.60%	4.22%	**-3.98%**	**-2.51%**	**-2.44%**	**-2.48%**	**0.15%**	**-1.48%**
2007-2017	1.55%	0.83%	0.76%	-1.06%	7.65%	6.60%	5.97%	6.35%	2.17%	4.71%	**-5.34%**	**-4.28%**	**-3.66%**	**-4.04%**	**0.14%**	**-2.40%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 44 vertically intergrated electric utilities.

[3]The annual growth rate of the U.S. Gross Domestic Product Price Index (GDPPI)

[4] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 1 of *Regulatory Reform for the Hawaiian Electric Companies* Exhibit 1-2018-0088. The formula becomes *growth* Scale [B] = 63.3% x [*growth* Retail Customers] + 12.9% x [*growth* Generation Capacity] + 13.2% x [*growth* Generation Volume] + 10.6% x [*growth* Transmission Line Miles].

[5]The annual growth rate of an average of the Edison Electric Institute's "Rate Case Summary" ROE and the embedded cost of debt from FERC Form 1 data of a nationally representative sample of electric utilities

[6]The growth rate of the average value of rate base at the start and end of the year

[7]The annual growth rate in total capital cost does not equal the sum of the annual growth rates of return on rate base [E] and depreciation and amortization [F].

[8]The annual growth rate in total cost does not equal the sum of the annual growth rates of capital cost [G] and O&M cost [H].

Pacific Economics Group Research, LLC

EXHIBIT B
DOCKET NO. 2018-0088
PAGE 17 OF 18

Results of this exercise can be found in Table 7. It can be seen that growth in the industry input price index was substantially more rapid on average than the growth in the GDPPI. Over the full 1997-2017 sample period, for example, industry input price growth exceeded GDPPI growth each year by 0.99% on average. The conclusion is that the tendency of the GDPPI to understate industry input price growth is the main source of the negative X factor values that PEG calculated.

We then considered the implications of this research for the HECO Companies. Suppose first that HECO had a revenue cap index like that in [5].

$$\textit{growth Allowed Base Revenue}^{HECO} = \textit{growth GDPPI} - (X^{Kahn} + \textit{Stretch}) + \textit{growth Scale}^{HECO}. \quad [6]$$

This formula would clearly yield substantially more revenue for each Company than the current RAM caps.

If an adjustment is deemed necessary to take account of the supplemental revenue provided by the MPIR tracker, one candidate formula is

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} - (X^{Kahn} + \textit{Stretch}) + 0.633 \times \textit{growth Customers}^{HECO}. \quad [7]$$

This formula escalates revenue for customer growth but not for growth in generation volume, capacity, or transmission lines since growth in these scale variables might be funded by the MPIR. At the extreme, the Companies could be denied all benefit of growth in *Scale*. The formula would then be

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} - (X^{Kahn} + \textit{Stretch}). \quad [8]$$

Results would vary with the stretch factor and the sample period used to calculate X^{Kahn}. Assuming a 0.20% stretch factor and an X^{Kahn} of -1.21% based on results for the full sample period the alternative revenue cap indexes would be

$$\begin{aligned}\textit{growth Base Revenue}^{HECO} &= \textit{growth GDPPI} - (-1.21 + 0.20) + 0.633 \times \textit{growth Customers}^{HECO} \\ &= \textit{growth GDPPI} + 1.01 + 0.633 \times \textit{growth Customers}^{HECO}. \quad [9]\end{aligned}$$

or

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} + 1.01. \quad [10]$$

Values of X would be more negative if based on results of our research for a shorter sample period.

Conclusions

Our statistical cost research for the HECO Companies suggests that a revenue cap index based on industry cost trends is likely to produce revenue growth that exceeds GDPPI inflation. One reason is that the GDPPI tends to understate utility input price inflation. Another is that VIEU productivity growth has slowed. A third is that revenue cap indexes conventionally include scale escalators.

Table 7

Decomposing the Kahn X Factor

Year	Kahn X Factor	GDPPI	Industry Input Price Growth	X Explained by Inflation Differential	X Explained by Productivity and Other Factors
	[A]	[B]	[C]	[D] = [B] - [C]	[E] = [A] - [D]
1997	-4.90%	1.70%	3.72%	-2.01%	-2.88%
1998	0.09%	1.08%	3.98%	-2.90%	2.99%
1999	5.45%	1.42%	0.61%	0.81%	4.63%
2000	-2.40%	2.25%	5.71%	-3.46%	1.05%
2001	0.06%	2.26%	2.04%	0.22%	-0.15%
2002	0.56%	1.52%	1.98%	-0.47%	1.03%
2003	0.80%	1.98%	2.10%	-0.12%	0.91%
2004	0.82%	2.71%	2.33%	0.37%	0.45%
2005	1.15%	3.17%	2.30%	0.87%	0.28%
2006	-0.53%	3.02%	2.89%	0.13%	-0.66%
2007	-1.35%	2.63%	3.08%	-0.45%	-0.90%
2008	-1.47%	1.91%	4.00%	-2.09%	0.62%
2009	-4.85%	0.78%	2.99%	-2.20%	-2.65%
2010	-4.60%	1.22%	3.01%	-1.79%	-2.81%
2011	-1.95%	2.04%	2.70%	-0.65%	-1.30%
2012	0.06%	1.82%	2.41%	-0.59%	0.65%
2013	-1.83%	1.60%	2.42%	-0.81%	-1.02%
2014	-2.38%	1.78%	2.46%	-0.68%	-1.70%
2015	-3.12%	1.06%	3.41%	-2.35%	-0.77%
2016	-3.42%	1.31%	1.21%	0.10%	-3.52%
2017	-1.49%	0.89%	3.58%	-2.69%	1.20%
1997-2017	-1.21%	1.82%	2.81%	-0.99%	-0.22%
2002-2017	-1.48%	1.84%	2.68%	-0.84%	-0.64%
2007-2017	-2.40%	1.55%	2.84%	-1.29%	-1.11%

Regulatory Reform for the Hawaiian Electric Companies

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Contents

1. Introduction

The Hawaiian Electric Company ("HECO") and its affiliated utilities, Hawaiʻi Electric Light Company ("HELCO") and Maui Electric Company ("MECO") (collectively "the Companies"), are challenged today by a pronounced version of changes affecting utilities worldwide. The ability of traditional cost of service regulation ("COSR") to address these changes has been questioned by many industry observers, and some find performance-based regulation ("PBR") to be a promising alternative. A new Hawaiʻi law requires greater use of PBR in electric utility regulation. Hawaiʻi's Public Utilities Commission ("PUC" or "the Commission"), already a PBR practitioner, has launched Docket No. 2018-0088 to develop a new PBR framework for the HECO companies.

Pacific Economics Group ("PEG") is a leading PBR consultancy that has been active in Hawaiʻi regulation since the 1990s. Work for mix of utilities, trade associations, regulators, government agencies, and consumer and environmental groups has given our practice a reputation for objectivity and dedication to good regulation. HECO has asked us to prepare a report that considers salient options for reforming Hawaiʻi electric utility regulation.

Our report begins with a brief review of the instant proceeding. We then consider the goals of utility regulation and various tools available to regulators for achieving them. This section includes a discussion of COSR and its limitations under modern business conditions. We then consider the current regulatory systems of the Companies and suggest some regulatory reforms. The current revenue adjustment mechanism ("RAM") cap is appraised in Section 7. An Appendix includes a glossary of terms and further discussion of some topics of special interest. These topics include Britain's innovative RIIO approach to regulation, which has many PBR provisions, and precedents for performance incentive mechanisms ("PIMs") in several jurisdictions.

2. PBR Reform in Hawai'i

Hawai'i law was recently revised to spur consideration of a new performance-based approach to electric utility regulation. The preamble to the law states that

> . . . the existing regulatory compact rewards utilities for increasing capital expenditures by basing allowed revenues on the value of the rate base . . . This same business and revenue model has been in place for over a century. The Wall Street Journal explained that "the more [utilities] spend, the more profits they earn", and called this "a regulatory system that turns corporate accounting on its head". . .
>
> . . . it may result in a bias toward expending utility capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by independent third parties.
>
> . . . although some utility performance incentives are being considered in existing dockets at the public utilities commission, any resulting performance incentives have not been transformative in urgently moving electric utilities toward the State's ambitious energy policy goals. . .
>
> The purpose of this Act is to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues.[1]
>
> The statutes were amended to include the following section:
>
> §269 – Performance incentive and penalty mechanisms
>
>> On or before January 1, 2020, the public utilities commission shall establish performance incentives and penalty mechanisms that directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels.[1]

The Commission recently opened Docket No. 2018-0088 to consider new PBR frameworks for the HECO Companies. Phase 1 of the proceeding has considered the goals of regulation, how the current regulatory system promotes these goals, and possible reforms to the PBR framework to promote them better. New performance metrics and PIMs have been a major focus. However, the Commission seems open to a broad range of PBR framework reforms. Phase II will consider implementation details.

Incentives for capital cost containment are a central concern in the proceeding. The PUC stated in its Opening Order that

[1] State of Hawai'i, Act 005, SB2939, SD2, pp 3-4, April 24, 2018.

> The Commission is interested in ratemaking elements and/or mechanisms that result in greater cost control and … efficient investment and allocation of resources regardless of classification as capital or operating expenses.[2]

Phase II will consider "PBR frameworks to move away from existing capital investment paradigm (e.g., a totex approach)."

[2] Hawai'i PUC Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, April 2018, p. 52.

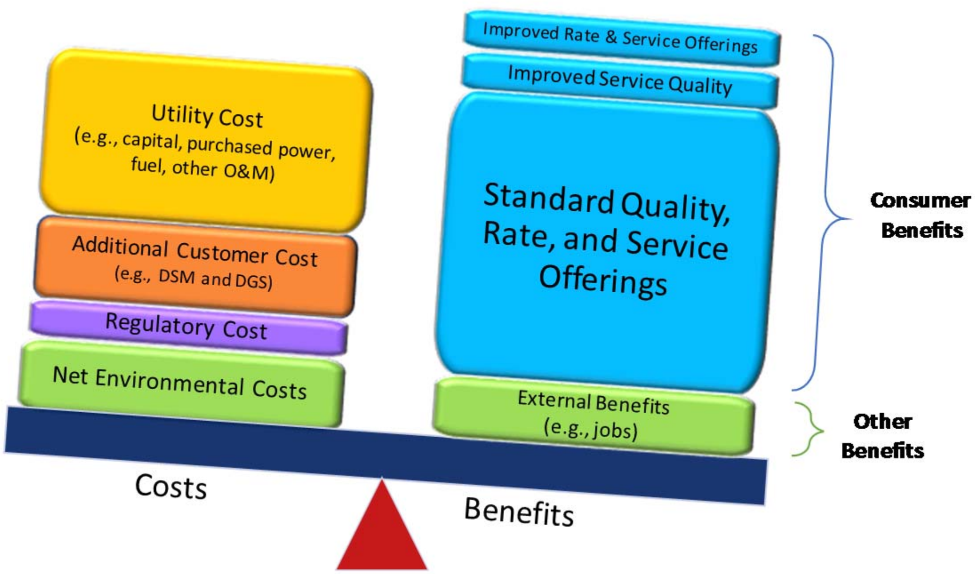
3. Policy Goals and Policy Tools

The power industry policies of government agencies should try to bolster the industry's net social benefits and share them fairly. The net benefits of the industry are the difference between its (gross) benefits and its costs. The benefits customers receive from power services are typically much larger than the cost of providing service.

The net benefit calculation is illustrated in Figure 1. Benefits and costs are multifaceted. We discuss them in turn.

Figure 1

Costs and Benefits of the Electric Power Industry



3.1 Power Industry Benefits

The chief benefit of the industry is the substantial value of power services to customers. Utilities "perform" when they provide services, and for this they receive compensation for the cost of these services. The value of services varies with their quality. Service is more valuable to the extent that it is reliable and customer requests for service are addressed promptly and effectively.

Optional rates and services can also benefit customers. For example, some customers may want green-power options that have less environmental impact than the utility's standard power "blend." Margins from optional rates and services that utilities provide may over time reduce the share of cost that must be recovered from traditional services. Some rate and service options can reduce the cost of service by, for example, reducing the need for peak load capacity.

3.2 Power Industry Costs

The costs of vertically integrated electric utilities ("VIEUs") like HECO include those that they incur for generation fuel, power, capital, labor, other services, and materials that they purchase. Consumers ultimately incur these costs as well as some of the costs for distributed energy resources ("DERs") such as conservation and peak load management [collectively called demand-side management ("DSM")], and distributed generation and storage ("DGS") on their side of the meter.

Power industry operations also produce environmental and aesthetic damage. In addition to relying more on renewable resources and conservation, the industry can lighten its environmental footprint by promoting the electrification of transportation ("EOT").

Regulatory cost is a non-negligible component of the power industry's cost which is of special concern to regulators. Regulation should be effective but efficient.

3.3 Importance of Fairness

An important and widely-accepted fairness principle is that utility revenue should roughly equal the efficient cost of service. The utility then has a reasonable chance to pay its suppliers and earn its target rate of return, which should be commensurate with its operating risk. This principle affects the cost of service as well as fairness since the utility businesses is capital-intensive and doubt about fair compensation can raise operating risk and the cost of raising funds in capital markets. Another common fairness principle is that electric services should be affordable to low income customers.

3.4 Goals of Commissions

The public utility commissions ("PUCs") that regulate utility rates are not the only branch of government setting power industry policies. Policies concerning the environmental impact and structure of the industry, for example, are chiefly the purview of legislatures and executive-branch agencies like the U.S. Environmental Protection Administration.[3] Policymakers in these branches of government can permit competition for services, such as power supply, which utilities have traditionally provided and impose environmental goals such as a renewable portfolio standard ("RPS").

The main job of the PUC is to encourage maximum net benefits from utility operations subject to constraints imposed by other branches of government on matters such as industry structure, environmental impacts, and fairness. Utilities should offer customers market-responsive quality, rates, and service packages at minimum cost while conforming to the legislated RPS. Utility revenue should cover the efficient cost of service. Power should be affordable to low income customers.

[3] Legislation and court decisions have also addressed fair compensation for utility services.

Many PUCs nonetheless also have some interest in and control over competition and environmental impacts. For example, they may have some control over the range of optional services that utilities and their affiliates can offer.

3.5 Competitive Market Analogy

Good utility regulation is sometimes characterized as simulating outcomes of well-functioning competitive markets. Such markets have some noteworthy attributes. Prices of products reflect the costs of typical firms, not those of individual suppliers. Prices are sensitive to product quality. Suppliers pay for most collateral costs of their operations so that there are few negative externalities.

Suppliers in competitive markets are incentivized to contain their costs and provide goods and services in the bundles and price/quality combinations customers want. They have no preference for capital cost over operation and maintenance ("O&M") expenses. Major tasks in the supply chain may be outsourced, including those that are capital-intensive. Competition between suppliers passes most benefits of industry performance gains to customers in the long run.

The revenue of competitive market suppliers is chiefly compensation for the cost of providing their products. The main “performance” customers pay for is the provision of the product. Superior performance is not required to earn a competitive rate of return.

3.6 Alternative Approaches to Power Industry Regulation

A wide range of tools are available to policymakers today to regulate the electric power industry. These can be usefully grouped into three broad categories:

- Structural
- Command and Control
- PBR (aka incentive) approaches

We discuss each of these approaches in this section. The diversity of tools available to policymakers is illustrated in Figure 2. Some tools are typically wielded by regulators while others are wielded by other branches of government such as state legislatures.

Structural Approaches

Policymakers influence power industry performance by their decisions concerning the structure of markets that utilities might serve. They can permit competitors to offer products to utility customers. Utility participation in some markets can be discouraged. Utilities may be required to outsource some of their functions to third parties. Outsourcing rules may contain competitive bidding requirements.

Procompetitive policies can unleash forces of competition that drive down costs. However, they can also bolster a utility's incentive to resist changes that reduce their earnings opportunities. For example, a utility could be incented to resist an accelerated transition to increased renewable reliance if

Figure 2

Basic Approaches to Power Industry Regulation

Public Service Commission	Other Branches of Government
Structural	
Competitive bidding framework	Independent energy efficiency provider
	Retail and bulk power supply competition
Command and Control	
Revenue requirements	Renewable portfolio standard ("RPS")
System planning & large capex projects	Energy efficiency portfolio standard
Rate designs	Appliance efficiency standards and building codes
Compensation for distributed generation	
Performance-Based Regulation	
Multiyear rate plans	Enhanced PBR (including more PIMs) mandated
Revenue decoupling	
Performance metric systems	
Targeted encouragement to use strategic inputs	

this transition has the potential to strand their fossil fuel investments and structural policy precludes their participation in new generation.

"Command and Control" Approaches

Policymakers have many opportunities to decide what utilities do. They can, for example determine the revenue requirement and its allocation between services. They can also have oversight over utility business plans, major capex projects, rate designs, and the terms of compensation for DGS power surpluses.

New kinds of command and control regulation have developed over the years. These include the following:

- Utilities may be asked to file integrated system plans, and these may address transmission and distribution as well as generation.

- Advanced approval of innovative “pilot” projects.
- An RPS or energy efficiency portfolio standard ("EEPS") may be imposed. An RPS may have a DGS "carve out."

Performance-Based Regulation

The term PBR encompasses approaches to regulation designed to strengthen utility incentives to perform well. These are discussed further in Section 5 below.

4. COSR and Its Limitations

4.1 The Basic Idea

The traditional cost of service approach to utility regulation has the following essential characteristics.

- A utility's base rates are revised at irregular intervals in general rate cases to reflect the costs that it incurs for capital, labor, materials, and services. Costs are sometimes deemed imprudent in rate cases and disallowed. The revenue requirement is reduced by the other operating revenue from miscellaneous non-tariffed services that the utility provides using rate-based assets. The revenue requirement is then allocated between tariffed services. Utilities are free to file rate cases as needed to address financial attrition.
- Costs for generation fuel and power that the utility purchases are typically tracked and promptly recovered using rate riders after expedited reviews.
- Rate designs are expressly approved by the regulator and may reflect a wide range of considerations that include affordability, cost causation, and appropriate price signals to inform customer usage decisions.

We provided a critique of COSR in a recent white paper for Lawrence Berkeley National Laboratory which merits summary here.[4] We commented that the efficacy of COSR varies with the business conditions that utilities face. The key business conditions that affect an electric utility's finances today include input price inflation, change in the usage of its system per residential and commercial customer (aka "average use"), and the need for capital expenditures ("capex"). To the extent that conditions like these are favorable, revenue growth between rate cases roughly matches (and can even exceed) cost growth. Rate cases are infrequent, so regulatory cost is low. Infrequent rate cases also strengthen utility performance incentives since utilities keep benefits of improved performance longer.

When business conditions are chronically unfavorable, however, cost tends to grow more rapidly than revenue. Utilities then tend to file rate cases more frequently, and this weakens their cost containment incentives. Regulatory cost is high, and this matters more to the extent that regulators have complicated issues to ponder.

Regulators understandably take measures to contain regulation's costs. Some of these measures have adverse consequences. For example, the scope and thoroughness of prudence reviews are contained, and this weakens utility performance incentives. Trackers for variable and/or rapidly rising costs can reduce the frequency of general rate cases and thereby reduce regulatory cost and help to preserve incentives to contain costs that are not tracked. However, incentives to contain tracked

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

costs are weakened unless the prudence of these costs is carefully reviewed. Regulators are also inclined to limit utility operating flexibility to the extent that rate cases are frequent, and the prudence of actions utilities might take with more flexibility is difficult to assess.

We conclude that traditional cost of service regulation does not work well when business conditions are chronically unfavorable. Utility performance tends to deteriorate just when customer bills are rising briskly. Growth in rate base becomes the primary path to earnings growth. Regulatory cost can be high.

It is also noteworthy that generation of power using fossil fuels harms the environment. Utilities in most American states pay no taxes for power plant emissions. Even if they did, these taxes might well flow through to customers via cost trackers. Traditional COSR thus produces weak utility incentives to reduce harmful generation emissions.

4.2 Usefulness Under Modern Business Conditions

Our analysis suggests that COSR is a less effective approach to regulation to the extent that utilities need frequent rate cases, operating flexibility is especially desirable, emissions from fossil-fueled generation are a concern, and regulators have numerous complicated issues to ponder. The question naturally arises as to whether these circumstances typify the present.

Key business conditions that affect the frequency of rate cases are considerably less favorable for the typical U.S. electric utility today than they were in the decades before 1970 when COSR became a tradition.[5] In the earlier period, growth in utility deliveries of power per residential and commercial customer (aka “average use”) grew briskly and, under legacy rate designs, helped utilities self-finance cost growth. Inflation was generally slow. We call the earlier period the “golden age” of COSR because this regulatory system worked well under these conditions.

In recent years, on the other hand, there has been mounting concern about carbon emissions from fossil-fueled power plants. For this and other reasons, policymakers and many utility customers have had an increased interest in energy efficiency programs and generation from renewable resources. In a few states such as Arizona and California, demand growth has also been materially slowed by increased distributed photovoltaic (“PV”) generation behind the meter. Nationwide, growth in residential and commercial average use of electric utilities is typically negative. Some utilities nonetheless need high levels of capex that don’t automatically produce revenue growth. This need is most commonly due to advancing system age.

We noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises concerns about the ability of electric utilities to cope with modern operating conditions when they are especially unfavorable. If utility performance incentives are weak, performance can deteriorate despite

[5] Ibid.

mounting competition. Utilities may, for example, choose such a time to accelerate replacement capex. Utilities may also be slow to address mounting environmental concerns.

The end result can be higher rates that further discourage use of grid services. This is a source of potential instability in the electric utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut costs.

The need for frequent rate cases varies among electric utilities today. Differences in the need for capex that doesn't automatically produce revenue growth is a major reason. In a period of sustained high capex, utilities need brisk and continual escalation in rates when capex does not automatically produce new revenue. Some electric utilities today need sustained high distribution capex to replace aging facilities, contend with large DG power surpluses, and/or to improve system reliability and resiliency. Technological change has created opportunities for advanced metering infrastructure ("AMI") and other "smart grid" capex that improves utility performance (e.g., accommodation of intermittent renewables).[6] The frequent rate cases and new cost trackers that grid modernization programs give rise to weaken incentives for utilities to manage these programs cost effectively.

Accelerated grid modernization makes rate cases more complicated in addition to making them more frequent. Many regulators lack experience with accelerated grid modernization proposals. They want to make sure that capex programs take account of O&M savings and non-wire alternatives ("NWAs") to capex such as DSM and behind the meter DGS. Regulators are also concerned about how to regulate new products and services that a smarter grid makes possible. DSM programs and new products can be offered by private energy service providers as well as utilities.

Distribution capex induces less growth in the total cost of a vertically-integrated electric utility ("VIEU") than it does in the cost of a UDC. Furthermore, slow demand growth and requirements by state regulatory commissions for VIEUs to buy rather than build generation capacity that *is* needed is reducing VIEU generation capacity additions. On the other hand, VIEUs sometimes need to refurbish or replace old power plants and reduce harmful generation emissions.

Regulatory resources that are currently devoted to electric rate cases have many alternative uses in this era of rapid change. Among the areas where thoughtful oversight is currently needed are integrated resource and distribution system planning, rate design, and compensation to DGS customers for the products they offer.

Marketing flexibility is increasingly useful for electric utilities. There is growing interest in green power packages and in miscellaneous new services that may be enabled by smart grid technologies. Greater reliance on intermittent renewable resources for power has increased the need for peak load management.

[6] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

4.3 Why Capital Cost Matters

There is a heightened concern about utility capital expenditures (“capex”) in many jurisdictions today. This is occasioned by many considerations. Capex produces half or more of the cost of utility base rate inputs. Some utilities need higher levels of capex today than they have for many years. Regulation can encourage excessive capex. Reduced capex opportunities and the risk of stranded capital costs can incentivize utilities to resist energy conservation and peak load management programs, behind the meter DGS, and utility-scale renewable generation owned by independent power producers ("IPPs").

To the extent that these incentive problems raise total cost, this is a legitimate concern of ratepayers and their representatives. To the extent that opportunities to reduce environmental damage are eschewed in the drive for a larger rate base, this will spark the concern of environmental groups. To the extent that power purchases are reduced, this will spark opposition from IPPs, DGS customers, and industries that produce, install, and maintain the equipment of these power producers.

While concern about excessive capital spending is understandable, it must be tempered by recognition of a few “inconvenient truths.”

- Generation, transmission, and distribution of power from renewable resources are capital-intensive activities. Therefore, utility eagerness to make investments is not necessarily at odds with increased renewable reliance. MidAmerican Energy, Xcel Energy, and several other U.S. electric utilities own extensive capacity to generate and transport power from renewable resources. A major reason for VIEUs to resist the embrace of DSM and DGS is fear of stranded capital costs. Many who voice concern about capex bias may thus presume that utilities should be precluded from owning new renewable generation or should not recover stranded costs.
- Remedies for excessive capex can pose their own serious problems. For example, return on rate base is a major component of capital cost. This depends on the rate of return on capital as well as the size of the rate base. Some proposed regulatory schemes intended to reduce utility capex bias may at the same time raise the required rate of return on capital. Consider also that utilities can easily spend too much on purchased power and offer excessive revenue credits for power received from DGS customers. Purchased power agreements (“PPAs”) have payment commitments like bonds that increase utility operating risk. Excessive outlays on acquired power is a problem for the general ratepayer but an opportunity for IPPs and DGS customers.
- A substantial portion of U.S. utility capex today is to replace aging distribution assets (“repex”), not system growth. Purchases of power from IPPs and DGS customers is not a substitute for most of this repex.
- It is possible for utilities to spend too little on capex rather than too much. For example, there are many opportunities today for beneficial load growth that backs out fossil-fueled

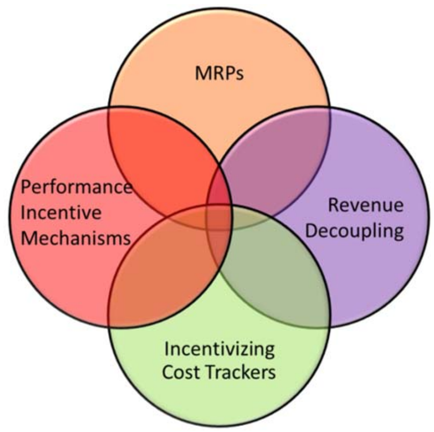
equipment. States without carbon taxes on generation fuels typically also do not impose these taxes on motor vehicle fuels.

5. PBR Alternatives

There are four well established PBR approaches. These are summarized in Figure 3.

Figure 3

PBR Approaches are Frequently Combined



We will discuss each of these approaches and the ways that they interact in turn.

5.1 Revenue Decoupling

A revenue decoupling mechanism ("RDM") causes a utility's actual revenue to track its allowed revenue more closely. This is usually accomplished with the aid of a balancing account. Allowed revenue does not grow with billing determinants, even though cost tends to rise, for inflation and other reasons. An RDM is therefore usually combined with some form of RAM that automatically escalates allowed revenue.

Decoupling is a form of PBR because it reduces a utility's throughput (aka lost margin) disincentive to embrace DGS, conservation, and peak load management between rate cases. Utilities are less resistant to rate designs that encourage DERs. This encourages use of DERs to reduce capex as well as energy cost.

5.2 Targeted Encouragement to Use Strategic Inputs

The Basic Idea

Cost trackers and associated rate riders facilitate recovery of targeted costs. If costs are recovered promptly with little risk of prudence disallowance, trackers can weaken the incentive to contain these costs. However, trackers nonetheless have constructive roles to play in modern regulatory systems, including PBR systems. Here are some notable advantages.

- Trackers for *large, volatile* costs can reduce utility operating risk and the need for frequent rate cases.
- Trackers for select *rapidly growing* costs can also reduce rate case frequency and have sometimes permitted parties to regulation to agree to a rate freeze.
- Trackers can facilitate fair outcomes when utilities are compelled to incur costs by policymakers. This rationale is particularly pertinent when a utility operates under an MRP since these plans restrict the frequency of rate cases that would be a means of seeking revenue relief.

"Strategic" inputs is the term we use for inputs utilities tend to use in sub optimally small amounts. Examples include inputs that reduce capex on balance or that reduce costs that are tracked or external to the company's finances. A disinclination to use inputs can increase when utilities operate under MRPs due to the stronger incentives to contain cost that these plans can create.

Inputs may also be disfavored because their use is unusually risky. An example would be equipment embodying a promising new technology. Utilities operating under multiyear rate plans may be reluctant to wait several years for the commission's verdict regarding innovative strategies.

Use of strategic inputs can be encouraged by

- tracking their cost for prompt or deferred recovery;
- capitalizing their cost;
- adding an ROE premium; and
- awarding the utility a share of the cost as a "management fee".

ROE premia and expenditure share awards may be linked to performance metrics and targets.

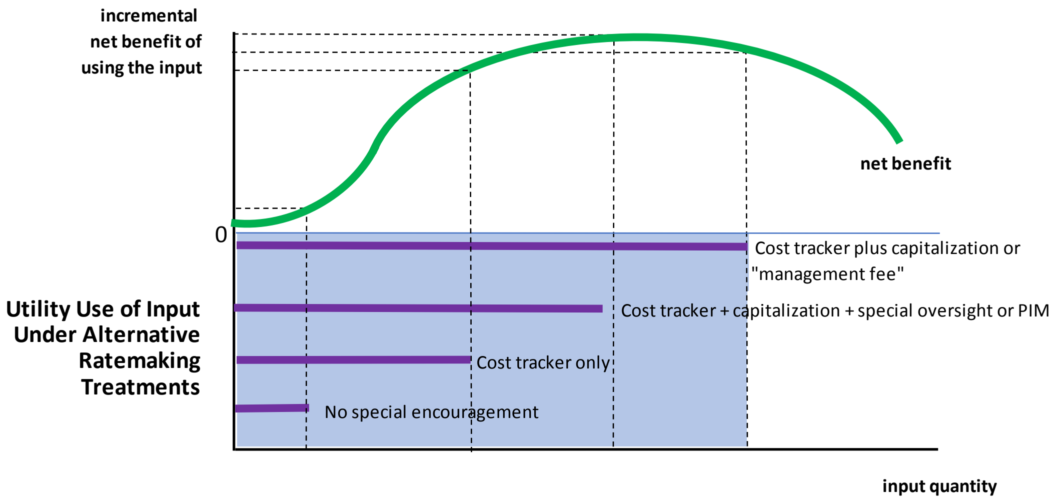
Cost trackers for strategic inputs are incentive mechanisms that target desirable actions. They may therefore qualify as performance mechanisms that directly tie an electric utility's revenues to its achievement on performance metrics under the meaning of Hawaiʻi Revised Statutes section 269.

Tracking the cost of strategic inputs can potentially weaken the incentive to contain them so much that an excessive cost is incurred. This problem can be mitigated by various means that include special prudence oversight, a partial pass through of cost variances, or the addition of a PIM to the regulatory system which shares net benefits from using the input.

The use of these incentive tools to encourage use of strategic inputs is illustrated in Figure 4. This figure has two panels. The upper panel shows that the incremental net benefit from using the input rises in a certain range but eventually falls from overuse. The lower panel shows how alternative ratemaking treatments can affect the utility's use of the input.

Figure 4

Encouraging Utility Use of Strategic Inputs With Trackers and Capitalization



Absent any encouragement, the use of the input can be seen in the example to be well below the optimum. If the cost of the input is tracked, utility use of the input is larger, but still sub optimally small. If the tracked cost is amortized with an ROE premium, usage in this example is higher but exceeds the optimal level. A more optimal level is achieved if there is also special oversight of the expenditure and/or there are special incentives to encourage correct use.

Salient Precedents

Many costs have been tracked based in part on the view that the inputs are disfavored by utilities because they reduce capex and/or costs that are tracked or external. Salient examples include costs of purchased power, utility DSM programs, and funding for DSM programs of independent agencies. Tracking of utility DSM expenditures is commonplace, and these expenditures are capitalized in several states. Trackers for DSM are frequently combined with PIMs that share the estimated net benefits of the program.

Here are additional costs that could in principle be tracked and/or capitalized based on the same reasoning:

- Premium payments to customers for DGS power surpluses at the right times and locations
- Costs incurred to improve handling of customer DGS surpluses
- Utility capex (especially for new technologies) which can/might lower total capex (e.g., storage pilots).

Regulators in many U.S. states have approved pilot programs and/or cost trackers for innovative activities. These include capital cost trackers for AMI and other smart grid pilots in Massachusetts, Oklahoma, and New Jersey; capital cost trackers for riskier generation technologies such as integrated gasification combined cycle facilities with carbon capture or new nuclear plants in Indiana, Ohio, Georgia, and South Carolina; and a compressed natural gas pilot program in New Jersey. The California PUC recently allowed for preapproval and deferral of pilot DER program costs. We discuss here in greater detail pilot programs and their cost recovery as adopted in Australia, California, and Great Britain.

Australia The Australian Energy Regulator ("AER") allows supplemental funding for innovative demand management projects. Demand management is defined as any act undertaken to modify the drivers of network demand. Eligible projects must aid demand management and be based on new or original concepts, involve technologies or techniques that have not previously been implemented in the relevant market, or be focused on customers in a market segment that have not been previously exposed to that technology. Some examples of innovative demand management projects include virtual power plants; tariff trials; embedded generation and storage deployments; and installing smart meters, conductors, and inverters. Distributor spending on these projects is limited to a share of their annual revenue requirement each year. The revenues and costs are tracked, with underspends returned to customers at the end of the MRP term. The distributor is at risk for any overspending.

California Innovative projects that advance clean energy goals are encouraged by Electric Program Investment Charge ("EPIC") Investment Plans in California.[7] These plans are presented to the California PUC every three years. The California PUC reviews the proposals and preapproves the costs for the EPIC Investment Plans and allocates costs to each of the state's three largest electric utilities. Each utility has a tracker to address these costs. Underspent funds are returned to ratepayers at the end of the 3-year plan with interest.

Great Britain The current generation of MRPs in Britain for power distributors and transmitters and gas utilities includes three methods for utilities to receive supplemental funding for innovative projects. These include an annual funding allowance as a percentage of allowed revenues through the Network Innovation Allowance, an annual competition called the Network Innovation Competition, and the option to apply for supplemental funding to roll out successful innovation projects called the Innovation Roll-out Mechanism. For the Network Innovation Competition and the Network Innovation Allowance, utilities must provide at least 10% of funding.

The Network Innovation Allowance provides supplemental funding for British utilities to undertake smaller innovative projects that potentially lead to lessons for the industry; produce net financial benefits for customers; are innovative and have unproven business cases; and do not duplicate already proposed pilot projects. Individual projects do not need to have their costs pre-approved, though utilities are required to submit an assessment of the project's eligibility and register the

[7] Most of the EPIC Investment Plans are administered by the California Energy Commission, with the utilities allowed to administer projects that demonstrate and deploy new technologies.

proposed project with an industry portal so that lessons may be shared with the industry. This cap for the allowance is set at the outset of the MRP term, based on Ofgem's review of utilities' proposed innovation strategies. The cap is between 0.5% and 1% of allowed revenues. Underspends are not retained by utilities and the utility is required to absorb overspends. If the pilot leads to direct financial benefits, they will be used to offset the costs of the pilot.

The Network Innovation Competition allows utilities to propose larger innovative projects that could deliver low carbon and environmental benefits to customers. Each year, utilities compete to present the best pilot projects as the funding through this mechanism is capped for each utility industry. Through this process, the winning projects are effectively pre-approved by Ofgem. Project underspends are returned to customers, while the utility absorbs the cost of overspending. Certain projects funded through the Network Innovation Competition are eligible to have the utility's contribution refunded if the utility files an application and demonstrates that the project had met its own criteria for rewards, had been delivered on time, and been well-managed with respect to cost and risk.

The Innovation Roll-out Mechanism allows utilities to request supplemental funding from Ofgem to deploy initiatives with demonstrable and cost-effective low carbon or environmental benefits.[8] The cost of the initiative's roll out must exceed a materiality threshold. Projects approved under the Innovation Roll-out Mechanism also receive a preapproval of their costs. Cost variances are shared in the same manner as those costs addressed by base revenues in the MRP.[9]

Totex Capitalization

Under totex regulation, a percentage of total O&M and capital expenditures is capitalized rather than capital expenditures and a small percentage of opex related to overheads. Total expenditures may exclude certain costs that the regulator believes are unusual and should be addressed separately.[10] Capitalized totex is then added to the rate base and depreciated or amortized as appropriate. The service life would not be determined based on the useful lives of assets but rather on a regulator's decision as to what the appropriate balance is between ensuring the financial stability of the utility and avoiding rate shock. This general approach has thus far been used only in combination with multiyear rate plans but may in principle be used in their absence. Further discussion of this topic is found in the companion paper of the Brattle Group.

[8] There are limited windows where utilities may apply to use this mechanism. For example, only 2 windows for applications exist during the power distributors' 8-year MRP term.

[9] This is discussed in more detail in the discussion on RIIO below.

[10] For example, the most recently completed power distributor MRPs in Britain ("DPCR5") excluded certain costs from capitalization. Instead, business support costs (IT, human resources, senior management, finance) and non-operational capital expenditure (equipment, vehicles, machinery) were expensed in their entirety.

5.3 Multiyear Rate Plans

The Basic Idea

Multiyear rate plans have the following essential characteristics.

- Rate cases are typically held every four to five years.
- There is often a need for utility revenue to grow between rate cases as compensation for input price inflation and other developments that affect utility finances. In an MRP, an attrition relief mechanism ("ARM") permits rates or revenue to grow in the face of cost pressures without closely tracking the cost that the utility actually incurs. This may be accomplished by determining the required cost growth in advance, by indexing allowed revenue to industry cost trends, or by a combination (aka "hybrid") of these two methods. In the balance of this paper we will assume that growth in allowed *revenue* (rather than *rates*) is capped so that this mechanism can be called a *revenue* adjustment mechanism.
- Costs that are difficult to address with the RAM may instead be addressed using trackers and associated rate riders or deferrals. Costs scheduled *in advance* for tracker treatment are sometimes said to be Y factored. Y-factored costs typically include those for generation fuel and purchased power and frequently also include pension and benefit expenses.
- Revenue adjustments are typically also permitted for hard to foresee events that are largely beyond utility control but affect utility finances. These events are sometimes said to be Z factored. Events commonly eligible for Z factoring include major storms, changes in accounting standards, highway construction programs, and changes in taxes and regulatory policies. We discuss Z factors further in Appendix Section A.2.
- A performance metric system, discussed further below, typically contains a PIM that links revenue to the utility's service quality.

A number of other provisions are sometimes added to MRPs. These include the following

- When an MRP features an indexed RAM, provisions are often made to provide supplemental revenue for unusually high capital expenditures if these are required during a plan. Cost trackers for major plant additions are used in British Columbia plans. Fixed "C factors" have been used in some Ontario plans to adjust for expected shortfalls in index-based capital revenue. Other Ontario plans have "capital modules" that permit a request for extra capital revenue during plans. These mechanisms are discussed further in Appendix Section A.1.
- Revenue decoupling and/or lost revenue adjustment mechanisms can reduce the sensitivity of earnings to DSM and DGS.
- Many plans have additional performance metrics and PIMs.

- Costs of some strategic inputs may be tracked and/or capitalized. Expenses for utility DSM programs and the funding of DSM programs by third parties are commonly tracked.
- Some plans feature an earnings sharing mechanism ("ESM") that shares the surplus or deficit earnings, or both, with customers when the utility's rate of return on equity ("ROE") varies from the commission-approved target.
- Off-ramp mechanisms may permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs.
- Some plans have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. These provisions can help utilities respond to the complex and changing needs of customers.
- Utilities may also be permitted (or required) to gradually redesign rates for standard services during the plan in fulfillment of commission-approved goals. For example, default rate designs for residential customers can move towards a time of use pattern. MRPs typically also do not preclude occasional reconsideration during the plan of rate designs and DGS compensation by commissions.
- To reduce regulatory cost and bolster incentives to achieve lasting efficiency gains, plans are sometimes extended or updated without a new rate case. If a rate case does occur, an efficiency carryover mechanism ("ECM") can permit the utility to keep a share of any lasting cost savings that are reflected in the new revenue requirement. ECMs are discussed further in the companion report of the Brattle Group.

In practice, the revenue from an energy utility MRP typically doesn't vary too far from the utility's cost for an extended period. Utilities aren't the only party to regulation that seeks to preserve some cost basis for MRP rates. For example, consumer groups are customarily wary of letting a utility's revenue fall substantially below its cost for lengthy periods.

MRP Precedents

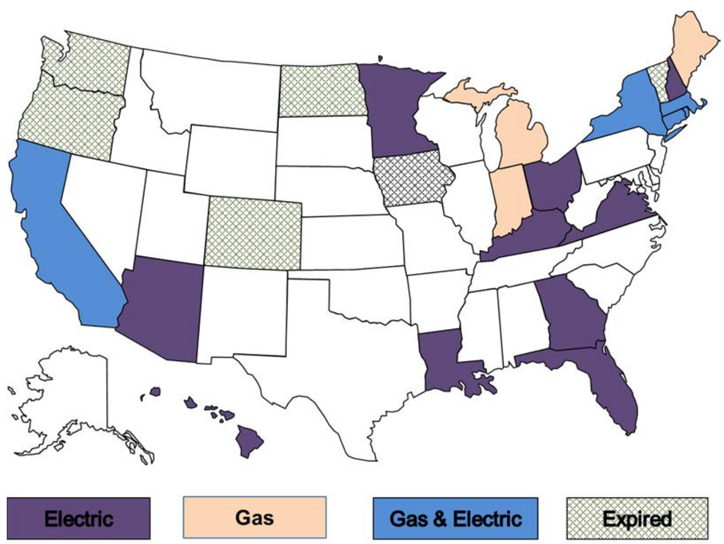
MRPs have been used in U.S. regulation since the 1980s. They were first used on a large scale for railroads and incumbent telecommunications carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated COSR. MRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. Both industries achieved rapid productivity growth under MRPs. Some states still use MRPs to regulate incumbent local exchange carriers.[11] The Federal Energy Regulation Commission ("FERC") uses MRPs to regulate oil pipelines.[12]

MRPs have also been used for many years to regulate gas and electric utilities.[13] California has used these plans since the 1980s. MRPs became popular in several northeastern states in the 1990s. In addition to MRPs, several states approved extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also been part of the ratemaking treatment for many mergers and acquisitions.

Figure 5 shows states that currently use MRPs to regulate retail services of U.S. gas and electric utilities. It can be seen that MRPs are now a fairly common alternative to COSR. Use of MRPs has recently spread to vertically integrated electric utilities ("VIEUs") in diverse states that include Arizona, Colorado, Florida, Minnesota, Virginia, and Washington.

Figure 5

MRPs for U.S. Energy Utilities



[11] See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.

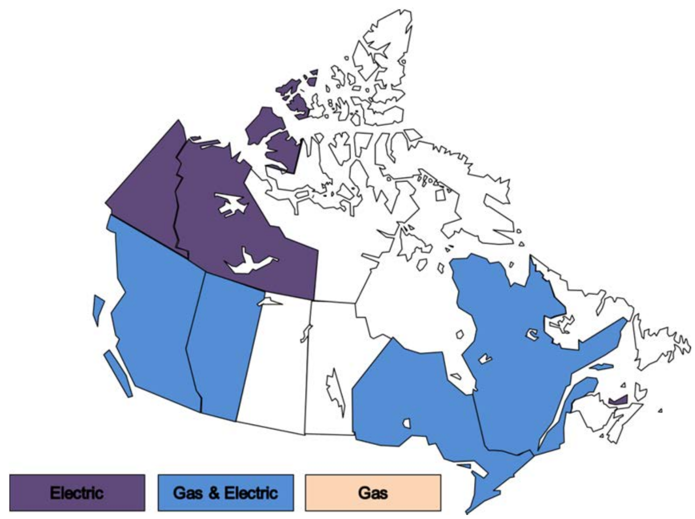
[12] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

[13] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The latest is Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

Figure 6 shows that MRPs are even more widely used to regulate Canadian energy utilities. Overseas, MRPs are the norm in Australia, Ireland, New Zealand, and Great Britain. Great Britain's approach to MRP design, called "RIIO", has drawn considerable interest in the United States. Countries in continental Europe which use MRPs include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MRPs are also common in Latin America.

Figure 6

Recent MRPs for Canadian Energy Utilities



Use of MRPs in some American states (e.g., California and Maine) has been driven by Commissions or lawmakers. In other countries, the impetus for MRPs has come from the public sector even more frequently. For example, provincial law in Quebec requires the Régie de l'energie to use approaches to regulation for Hydro-Québec, the large VIEU in the province, which streamline regulation, encourage performance gains, and share benefits with customers.[14] The Régie recently approved an MRP for Hydro-Québec's power distributor services. Utilities in some jurisdictions have mounted legal challenges to MRPs that regulators have chosen.

[14] National Assembly of Québec, 40th legislature, 1st session, Bill n°25 (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed June 2013.

MRP Pros and Cons

General Arguments

Advantages MRPs have several general advantages over COSR. The RAM can provide timely rate escalation for increasing cost pressures. This permits an extension of the period between rate cases. These are increased opportunities for utilities to bolster earnings from efforts to contain growth in the rate base and other costs that are addressed by the RAM (i.e., costs that are not tracked). There is more incentive to buy services rather than build when this is the low-cost alternative. The RAM thus reduces operating risk while strengthening performance incentives. Avoiding a full true up of revenue to the company's cost when the plan expires by such means as an ECM can magnify the incentive "power" of the plan.

We have already noted that provisions can be added to MRPs which strengthen a utility's incentive to embrace DSM and DGS. MRPs can, by strengthening general incentives to contain cost, also provide their own incentive for utilities to use DSM and DGS to contain load-related costs of base rate inputs such as load-related capital expenditures. A utility might, for example, be more incentivized to use DSM and well-sited customer DGS to reduce the need for a costly distribution system upgrade. Time of use pricing has more appeal since this can help contain growth-related costs.[15] Note also that MRPs strengthen incentives to embrace DSM and DGS without requiring complicated load or cost savings calculations. The combination of an MRP, revenue decoupling, demand-side management PIMs, and the tracking of DSM-related costs can thus provide four "legs" for the DSM "stool."[16]

To the extent that products and services aren't subject to revenue decoupling, an MRP can also strengthen incentives to market them effectively. This is a useful attribute in an era when changing technologies and customer needs create opportunities for new rates and services. Services to price-sensitive, large-volume customers are sometimes exempted from decoupling and the other operating revenues from miscellaneous non-tariffed services usually are.

The PIMs included in the plans also play a role in encouraging good performance. For example, we have noted that MRPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall materially if the quality of its offerings falls below industry norms. Moreover, customers of firms in competitive markets provide no relief if a company's safety problems trigger costly lawsuits. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.

[15] Railroads operating under MRPs used pricing provisions aggressively to encourage less costly service requests.

[16] A *three*-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in Dan York and Martin Kushler, "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," ACEEE, September 2011.

MRPs can also encourage good utility performance by increasing operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency and reliance on RAMs for revenue escalation means that the prudence of utility actions must be considered less frequently. Utilities are more at risk from bad choices (e.g., needlessly high capex) and can gain more from good choices (e.g., reductions in O&M expenses that do not reduce service quality). Knowledge of stronger incentives informs prudence reviews when they are made. One area where the advantage of MRPs in facilitating operating flexibility has been developed is marketing flexibility.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. The strengthened performance incentives can encourage a more performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, the occasional rate cases, an efficiency carryover mechanism, and/or careful RAM design.[17]

MRPs can also improve the efficiency of regulation. Rate cases are less frequent and can be better planned and executed. The terms of MRPs of utilities in the same jurisdiction can be staggered so that rate cases overlap less. Streamlining the rate escalation chore can free up resources in the regulatory community to more effectively address other important issues. Senior utility executives have more time to attend to their basic business of providing quality service cost-effectively.

Disadvantages MRPs also have disadvantages, and these have limited their adoption in the United States.[18] They are complex regulatory systems that require skills that the regulatory communities in some states do not possess. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise over plan design, as they do in COSR over different issues such as the prudency of costs and the target rate of return on equity. The main sources of controversy in a typical MRP proceeding is the appropriate RAM and the need for supplemental capital revenue. There are opportunities for strategic behavior that erodes potential plan benefits. These and other concerns have prompted many consumer advocates to oppose MRPs. Since rate cases are still held occasionally, utilities may resist innovative but risky business plans that might lead to later prudence disallowances. Best practices in the MRP approach to regulation have evolved to address some of these problems.

Note also that MRPs typically track costs of generation fuel and of power purchased from fossil-fueled generation. They therefore may not provide any special incentives to contain fossil fuel costs.

[17] Customers can also benefit from the more predictable rate growth that MRPs make possible. Rate trajectories can be sculpted to diminish rate bumps.

[18] For further discussion of disadvantages of MRPs see Costello, K., *Multiyear Rate Plans and the Public Interest*, for National Regulatory Research Institute, October 2016 and Lowry, M. N., and Woolf, T., *Performance-Based Regulation in a High Distributed Energy Resources Future,* for Lawrence Berkeley National Laboratory, January 2016.

5.4 Performance Metric Systems

The Basic Idea

Performance metric systems aid measurement of utility performance in areas of special concern to customers and the public. These systems typically involve several metrics. Targets are established for some metrics, and performance can be gauged by comparing the utility's values for these metrics to the targets. Metrics and targets provide the basis for PIMs that link a utility's revenue to its measured performance in targeted areas. Performance metric results are sometimes summarized on scorecards that are available to the public.

Metric Pros and Cons

Performance metric systems have notable pros and cons as additions to utility regulation.

Pros

- PIMs can strengthen financial incentives to perform well in targeted areas that matter to regulators, customers, and the general public. Utilities that try to perform well in targeted areas can garner valuable goodwill from regulators and the public even in the absence of financial incentives.
- Metric systems can evolve incrementally and gradually as new performance concerns arise and older concerns recede.
- PIMs can sometimes reduce the need for prudence oversight. For example, PIMs for reliability can reduce the need for formal reviews of reliability during MRPs.
- Other means of strengthening incentives and/or reducing regulatory cost may be less practical. For example, incentivization of cost trackers can be difficult for costs that are especially volatile. Regulators may balk at implementing MRPs or more avant-garde MRP provisions such as efficiency carryover mechanisms.

Cons

One disadvantage of performance metric systems is that performance is often difficult to measure. Some utility activities are hard to quantify. An example is utility efforts to encourage development of markets for DSM products and services. Some performance metrics (e.g., reliability and peak loads) are quite sensitive to external business conditions, and these conditions are sometimes volatile. The utility is not then fully responsible for apparent failures and successes. Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities. The impact of external business conditions on performance metrics may be unclear and/or complicated. These problems can make it difficult to base performance targets for many metrics on operating data from other utilities.

It can also be difficult to correctly *value* performance and establish appropriate award/penalty rates for PIMs. The value of performance (e.g., reductions in carbon emissions) is sometimes unclear. Even where it is known, the share of benefits that utilities should receive may be unclear. Compensation should not exceed that needed to incentivize good behavior. Concerns about overpayment for performance have prompted many consumer advocates to oppose PIMs with awards. The appropriate PIM may have a nonlinear form, so that award rates rise or fall with measured performance.

Here are some other problems encountered with PIMs.

- Utilities tend to resist PIMs involving penalties and to propose lenient targets, while consumer groups tend to resist PIMs involving awards and to propose aggressive targets.
- Regulators may have difficulty committing long term to a PIM.
- "Ratcheting" targets to reflect improving performance can weaken incentives.
- When there are multiple PIMs, the incentives they generate may overlap. Assigning weights to individual PIMs can be a controversial task.

These disadvantages of PIMs have consequences.

- The design and operation of PIMs can invite controversy and strategic behavior by parties to regulation. For example, utilities and other parties to regulation have sometimes disagreed on the load impact of DSM programs that are addressed by PIMs.[19] Awards and penalties have sometimes been disputed when metrics have been influenced by external business conditions.[20]
- The incremental regulatory cost of adding several metrics and new PIMs to a regulatory system can be material. A performance metric system can in principle grow so large and complex as to constitute an undue administrative burden.
- PIMs can increase utility risk without an appropriate rate of return adjustment.
- Targets, penalties, and rewards may be too high or too low.
- Utilities may be incentivized to focus on performance dimensions that are more quantifiable and neglect dimensions that are less quantifiable but nonetheless worthwhile. For example, they may focus on utility DSM programs rather than market transformation initiatives. Amongst their programs, utilities may focus on initiatives where savings are easier to measure. For example, they might prefer direct load control (i.e., dispatchable) programs to time variant pricing.

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[19] Gold, R., Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency? *The Electricity Journal*, November 2014, p. 89.

[20] *Ibid*., p. 90.

- A focus on *summary* metrics can, on the other hand, encourage utilities to focus too much on what's easy while neglecting more difficult initiatives that are also desirable. For example, they may focus on achieving good reliability on urban circuits and neglect rural circuits that serve few customers.

Performance Metric Systems in Practice

Approved performance metric systems reflect these considerations.

- PIMs tend to be limited to situations where incentives are unusually weak and performance really matters. In searching for incentive "holes," the full range of structural, command and control, and PBR provisions of the regulatory system should be considered.
- PIMs also tend to be used where they are easy to develop and administer and/or savings on traditional prudence reviews are large. For example, MRPs tend to have *reliability* metrics but often do not have *cost* PIMs because the stronger cost containment incentives generated by MRPs raise concerns about reliability but reduce concerns about cost containment and cost performance appraisals can be complex and controversial.
- Most PIMs for demand-side management involve only awards.[21]
- Awards and penalties are often small, and rewards may be arbitrarily capped.
- Many metrics in a performance metric system will have targets but no PIMs. Some metrics will have neither targets nor PIMs.
- Complex calculations are often eschewed in PIM design. For example, the award and penalty rates of service quality PIMs rarely reflect sophisticated calculations of the costs or benefits of changes in quality. California's Public Utilities Commission has abandoned the shared savings approach to the calculation of awards for DSM programs. Utilities instead receive a share of DSM expenses as a management fee.
- Some PIMs have dead bands or adjustments like Z factors to reduce the impact on awards and penalties of volatile external business conditions. For example, many reliability metrics exclude major event days because these days are typically the result of unusually severe weather or other extraordinary events.
- Targets (e.g., those for reliability metrics) are often company-specific and not based on operations of other utilities.
- Some metrics "self-correct" for the impact of important external business conditions. For example, unit cost and SAIFI are metrics that control for influence of operating scale on utility cost and outage frequency, respectively.

[21] *Ibid*., p. 89.

Metric Precedents

Performance metric systems were noted above to be a standard feature of MRPs. Most MRPs have service quality PIMs. These are intended to encourage the maintenance or improvement of quality in the face of stronger cost containment incentives.

Even when plans have revenue decoupling and trackers for DSM expenses, they often also have PIMs for energy conservation since these provide a “positive” incentive to use DSM to reduce capex and costs that are tracked or external to the utility’s operations.[22] These mechanisms often have a “shared savings” format that can guard against inefficient use of strategic inputs. Calculation of net benefits can be quite complicated and is sometimes controversial.

Interest in using performance metrics in utility regulation has been growing in the U.S., spurred in part by the elaborate performance metric system in Britain’s “RIIO” approach to energy utility regulation. As discussed further in Appendix Section A.4, RIIO includes several PIMs and numerous additional metrics. Some of the PIMs are quite innovative.

Metric systems are evolving to meet new industry challenges. Metrics that address concerns of policymakers are sometimes called policy metrics. These metrics are sometimes used to construct PIMs. The new policy PIMs are usually asymmetrical and often reward-only.

Examples of metrics used in U.S., Canadian, and British utility regulation today are summarized in Table 1. We provide here a high-level summary of the precedents. Appendix Section A.3 includes in-depth discussions of the policy PIM precedents in New York, Rhode Island, California, and Australia.

Some metrics address concerns by regulators and many stakeholders that utilities increase the effectiveness of peak load management to facilitate greater reliance on intermittent renewable resources and contain growth-related capex. A second concern is to ensure that customers are getting value from innovative smart grid projects such as AMI deployment, the cost of which is frequently tracked. AMI benefits include specific performance improvements associated with the deployment of AMI. Some of these benefits include reductions in consumption on inactive meters, unaccounted-for energy use, and meter reading costs.

Peak load management metrics focus on the success of peak load management programs. Metrics include the level or change in peak demand at specific times (e.g., system coincident peak). Peak load management metrics have been tied to financial incentives. Here are some key issues in the design of such PIMs.

- Focus on *utility* peak load management programs, *all* programs, or the trend in normalized peak load? A focus on all programs can reward the utility for outsourcing peak load management to energy service providers.

[22] Conservation and service quality PIMs have been popular nationally even in the absence of MRPs.

Table 1

Notable Precedents for Policy Metrics

Performance Area	Metric Definition	Jurisdiction
AMI Benefits	Number and % of distribution circuits using data from AMI meters as part of voltage/var control scheme	IL
AMI Benefits	Consumption on inactive meters	IL
AMI Benefits	Unaccounted-for energy use	IL
AMI Benefits	Meter reading cost reduction	MD
Customer Engagement	Customer awareness survey of AMI technology, features, and benefits	NY
Customer Engagement	Number (or %) of customers who have authorized utility to provide 3rd parties with energy usage data	CA
Customer Engagement	Number (or %) of customers enrolled in DR or dynamic pricing programs	CA, HI, IL, MA, MD, NY
Customer Engagement	% EV customers enrolled in time-variant tariffs	CA, HI
DER Utilization	Number (or %) of customers with DGS	CA, HI
DER Utilization	MWh (or %) delivered from customer-side DG	CA, HI
DER Utilization	DG Capacity (kW)	IL
DER Utilization	Known DG capacity as a percentage of system peak	IL
DER Utilization	Energy Storage Capacity	HI
DER Utilization	Sum of annualized production from DG and fuel cells plus avoided consumption from demand response, consumption by thermal storage, and charging of battery storage and EVs	NY
Greenhouse Gas Emissions	Avoided metric tons of carbon dioxide emissions from beneficial electrification	NY
Greenhouse Gas Emissions	Greenhouse gas emission reductions due to reduced use and demand after AMI deployment	IL
Peak-load management	Peak load reduction	NY
Peak-load management	Cumulative summer/winter coincident peak demand savings	VT
Peak-load management	Weather-normalized coinicident peak demand	NY
Procurement	Cost of DER procurements	CA
Procurement	Cost of Long-term renewable contracts	RI
Procurement	Cost per kWh of renewable contracts (with and without storage)	HI
Service Quality for DG Customers	Time to issue an executable Interconnection Service Agreement	MA
Service Quality for DG Customers	Completion of installation work on time	GB, ON
System Use	Residential Use per Customer	NY
System Use	Commercial Use per Employee	NY
System Use	System Load Factor	IL
Utility emissions	% reduction in emissions associated with reduced truck rolls due to AMI	PA
Utility emissions	Reduction in greenhouse gas emissions to respond to outage or maintenance calls	IL
Utility emissions	Total carbon dioxide equivalent emissions by business function	GB
Utility emissions	Line losses	GB
Utility emissions	Sulfur hexaflouride emissions	GB
Utility emissions	Number of utility vehicles that are electric	DC

- Focus on the *system wide coincident* peak that influences transmission cost or the *local network* peaks that influence distribution cost?
- Focus on *all* utility programs or a local project such as Con Ed's Brooklyn/Queens Demand Management project?

Utility emissions focuses on the emissions resulting from the utility's management of the system. Metrics for this performance area include reductions in emissions due to fewer truck rolls, carbon dioxide emissions by business function, line losses, sulfur hexafluoride emissions, and the number of utility vehicles that are electric.

PIMs for Total Cost, Capital Cost, and Capex Regulators in several countries use sophisticated benchmarking methods to appraise the total cost, opex, capex, and/or totex performance of utilities. The Ontario Energy Board benchmarks total cost. The Australian Energy Regulator has developed models to benchmark opex and augmentation (growth related) and replacement capex. In Britain extensive benchmarking is undertaken both at the level of total expenditures and by cost category.

Targets for cost metrics are often developed using econometric cost modelling. This is the case in Ontario, where distributors report their performance in the Board's econometric total cost benchmarking study as part of their scorecard. The Australian Energy Regulator and Ofgem use econometric benchmarking for opex and totex, respectively.

Four Myths About Performance Metrics

Misconceptions are prevalent about the actual and potential use of metrics in regulation. This seems due in part to a misunderstanding of how metrics are used in British regulation. Here are some popular misconceptions and the contrasting realities.

Myth: The cutting edge of regulation today is to base revenue largely or entirely on PIMs.

Reality: MRPs are the core of a state-of-the-art regulatory system. These plans usually contain performance metric systems with several PIMs. Most regulators who have taken the lead in adopting "policy" PIMs (e.g., California, New York, and Britain) are MRP practitioners. The performance metric systems are designed to complement other MRP provisions.

Myth: Utilities should "earn" their allowed ROE by scoring well on PIMs.

Reality: Procurement and delivery of power at the right time and place is the most important dimension of electric utility performance. Compensation for this performance does not require PIMs. PIMs can nonetheless play a role in *adjusting* compensation to reflect service quality and other considerations.

Myth: PIMs are necessary to reduce utility incentives to grow rate base.

Reality: Under any regulatory system, utility revenue is chiefly compensation for the cost of service. The regulatory systems available to establish rates have varied incentive properties. A strong incentive to contain capex can be accomplished without PIMs.

If a PIM was used to strengthen capex containment incentives, it would make sense for it to be a cost efficiency PIM. However, the design of a cost efficiency PIM involves many of the same challenges encountered in the design of a revenue adjustment mechanism. It does not make sense to overpay for other performance dimensions as a means of strengthening capex containment incentives.

Myth: Britain's "RIIO" system of regulation is a performance metric system.

Reality: RIIO features multiyear rate plans that include performance metric systems. Other aspects of these plans such as the design of revenue adjustment mechanisms command a great deal of the British regulator's attention.

Myth: A substantial portion of ROE is at risk in the RIIO system.

Reality: This is true, but the big weights in the RIIO PIMs are on reliability and an information quality incentive that encourages utilities to file truthful evidence on future cost growth. Many metrics in RIIO performance metric systems have no PIM.

5.5 Choosing a Regulatory Reform Strategy

Our survey has identified numerous and varied tools for encouraging good utility performance under contemporary operating conditions. Each involves its own incentives, risks, and regulatory cost. Quite often, extreme reliance on a single tool produces suboptimal results. Here are some examples.

- We have noted that revenue decoupling removes a disincentive to embrace DSM and customer DGS but does not encourage a utility to offer the right DGS revenue credits or to promote EVs and other beneficial electrification.
- Tracking and/or capitalizing costs of strategic inputs encourages their use but can result in excessive cost for the inputs. For example, tracking power purchases from independent renewable generators removes a disincentive for making these purchases but does not incentivize a utility to incur the right costs for the right quantities. Furthermore, PPAs are long-term contracts that raise utility operating risk.
- Prudence reviews, integrated system planning, and PIMs that share net benefits involve high regulatory cost.

A complex set of tools may thus be needed to provide the right "checks and balances." The optimal mix typically includes structural, command and control, and PBR mechanisms. To the extent that command and control and structural provisions address challenges, there is less need for incentive provisions. For example, incentives for utilities to reduce fossil fuel costs matter less to the extent that conservation programs are managed by independent agencies.

Part of the art in designing PBR mechanisms is to determine how best to incentivize better performance without producing unnecessary risk. To see this, consider the following decomposition of generation fuel cost.

$$Cost^{Actual} = Quantity^{Actual} \times Price^{Actual}$$
$$= [Quantity^{Planned} \times (Quantity^{Actual}/Quantity^{Planned})] \times$$
$$[Price^{Expected} \times (Price^{Actual}/Price^{Expected})].$$

The actual cost of generation fuel varies greatly with the fluctuation of the actual price around the expected price. Cost is also sensitive to the variation of quantity of fuel around its expectation. If the goal is to encourage lower usage of fossil fuel, unnecessary risk can be avoided by targeting reductions in the quantity used and/or the resultant emissions and/or the planning that can lead to reduced quantities.

6. Application to the HECO Companies

6.1 Salient Business Conditions

The HECO Companies are vertically integrated electric utilities serving an archipelago of small, isolated tropical islands.[23] These circumstances expose the Companies to especially marked versions of challenges facing electric utilities worldwide today. Power service using traditional technologies tends to be unusually costly due to an inability to achieve scale economies. Partly for this reason, a competitive bulk power market is unavailable for purchases of backup supplies, and utility-scale independent power producers require long-term PPAs. Oil-fired generation has traditionally been the low-cost resource on small tropical islands, but oil prices are volatile and frequently high in today's economy.

Meanwhile, strong sunlight adds to declining cost and other advantages of distributed solar generation and storage to make it an increasingly competitive alternative to traditional technologies. Strong wind adds to the increasing cost advantages of wind farms in the islands but limited space, economies founded on tourism, and residents who particularly value natural beauty place practical constraints on this option. Wind power has more promise on Molokai and the Big Island but prospects for exports to Oahu, Hawai'i's main load center, are dimmed by local resistance and the sizable cost of inter-island connections.

Under these conditions, the HECO Companies have in the last decade experienced an unusually high rate of behind the meter DGS penetration. This phenomenon, together with sizable energy conservation programs, has greatly slowed growth in the Companies' power sales volumes. Slow volume growth materially slows each Company's revenue growth as well. One bright spot in the demand outlook is that the small size of the islands makes EVs a more practical alternative to petroleum-fueled vehicles than in many mainland regions.

The slow revenue growth of the HECO Companies coincides with material cost pressures. Sizable investments in new facilities are required to integrate large amounts of intermittent renewable resources. Many grid assets are approaching replacement age. The decline in bond yields that has for many years moderated utility input price inflation has ended. These circumstances would lead to frequent rate cases under traditional COSR which raise regulatory cost and weaken performance incentives.

[23] The Big Island, which is the largest in the archipelago, ranks 75th in the world in terms of area and is smaller than Jamaica or Sardinia.

6.2 Hawai'i Regulation

The regulatory system of the HECO companies features a complicated mix of structural, command and control, and incentive provisions. We summarize some salient provisions of each kind in turn.

Structural Provisions

The HECO Companies make all retail sales in the islands they serve but must, with some exceptions, conduct competitive bidding for new generation. A sizable portion of power supplies are purchased, and this share is likely to grow. Most power purchases involve long-term (e.g., 20-year) PPAs. This will materially increase the Company's operating risk. The cost of these PPAs will be a sizable portion of customer bills.

Customers are largely free to own DGS facilities and the Companies are obliged to handle their power surpluses. This subjects the Companies to substantial competition while raising distribution costs. Conservation programs are administered by an independent agency whereas utilities in most American states run most conservation programs.

Command and Control Provisions

The revenue requirements of the HECO Companies are periodically rebased to their cost of service in general rate cases. These cases use forward test years. Allocation of costs to services and the design of rates are carefully considered. Rate cases normally take more than a year to process and reach a final decision.

The Commission closely oversees rate designs and terms of compensation for DGS customer power. In one docket the PUC closed the HECO Companies' net metering programs to new customers, and eventually replaced net metering with several successor compensation programs.

Advanced approval has long been required for major capital improvement projects.[24] These are defined as projects involving more than $2,500,000 of capex. Utilities are also required to file annually their projected capital improvements program budget for a 5-year period.

The HECO Companies filed integrated resource plans for many years until the PUC rejected the Companies' proposed plan in 2014. These plans have been superseded in recent years by various planning filings, including a Power Supply Improvement Plan and a Distributed Generation Interconnection Plan. The Companies also recently filed a Grid Modernization Strategy. This outlined a proposed deployment of various smart grid technologies including an outage management system, substation automation, and advanced inverters. In 2018, the Companies proposed a new approach to planning called Integrated Grid Planning, which would weld these disparate plans and consider power supply, transmission and distribution jointly. This proposal is pending.

[24] If the PUC does not render a decision within 90 days of filing, the company can add the project to rate base.

The state of Hawai'i has one of the most aggressive renewable portfolio standards in the nation. State law specifies renewable portfolio targets of 30% of net electricity sales by December 31, 2020, 40% by December 31, 2030, 70% by December 31, 2040, and 100% by December 31, 2045. Given the practical constraints on wind power, this is likely to mean unusually high reliance on DGS, especially on Oahu.

The state also has an energy efficiency portfolio standard. The target is 4,300 GWh of savings by 2030, with an annual incremental savings goal of 195 GWh. Conservation has been growing in importance in meeting Hawai'i's demand, increasing an average of 12.7% annually since 2005.[25] The most recent ACEEE scorecard ranked Hawai'i's electric DSM programs as having a top 10 net incremental DSM savings as a percentage of sales performance in the U.S.

PBR Features

The regulatory systems of the HECO Companies includes several kinds of Altreg mechanisms, many of which can be categorized as PBR mechanisms.

Revenue Decoupling

Revenue decoupling mechanisms called Revenue Balancing Accounts ("RBAs") compensate the Companies for margin losses between rate cases which result from a decline in sales. Decoupling currently encompasses all tariffed services but not other operating revenue.

Multiyear Rate Plans

The HECO Companies, unlike most American utilities, also operate under multiyear rate plans. These plans address transmission as well as generation and distribution costs. The transmission services of most American utilities are, in contrast, subject to formula rate plans which generate particularly weak cost containment incentives.

The RAMs in the Companies' plans feature O&M indexes for bargaining unit labor and non-labor expenses. Recovery of baseline plant additions is based on a rolling 5-year historical average of baseline plant additions. Since 2015, each Company has had a RAM Cap limiting the annual escalation of each Company's target revenues to the inflation in the U.S. gross domestic product price index ("GDPPI").

Asymmetric ESMs require each Company to return a share of earnings to customers when its ROE exceeds its target. The ESMs feature multiple bands with customers receiving a higher share of incremental earnings at higher ROEs.

[25] This data includes generation by Kaua'i Island Utility Cooperative.

Cost Trackers

Each Company has several cost trackers.

- Major Project Interim Recovery Adjustment Mechanisms ("MPIRs") address costs of capex for major projects, net of any related benefits that can be quantified and realized by the Companies if they aren't already offset in rates. These mechanisms cap recovery at the lesser of forecasted or actual cost.
- A Renewable Energy Infrastructure Program ("REIP") surcharge can in principle expedite recovery of capex and other related costs incurred to accommodate renewables on a project by project basis. To date, this mechanism has been used sparingly.
- The Companies have trackers for costs of generation fuel, with an adjustment for generator heat rates, and purchased energy costs.[26] In its most recent rate case, the PUC decided to change HECO's Energy Cost Adjustment Clause into an Energy Cost Recovery Clause ("ECRC") such that test year fuel and purchased energy costs are no longer rolled into base rates. A fossil fuel cost risk sharing mechanism requires HECO to absorb (retain) 2% of fossil fuel cost variances relative to baseline prices that are reset annually, as adjusted for generator heat rates, up to a cap of $2.5 million. HELCO and MECO's ECAC will also be converted to an ECRC and test year fuel and purchased energy costs will be removed from their base rates subject to PUC decision and order in their respective rate cases.
- Purchased Power Adjustment Clauses ("PPACs") allow the HECO Companies to pass through costs of PPAs with third parties which are not addressed by the ECACs/ECRCs or base rates.[27]
- The HECO Companies have tariff sheets called Integrated Resource Planning Cost Recovery Provisions with DSM adjustments that recover certain costs of existing load management programs. Public benefits fund surcharges address costs of funding Hawai'i Energy. The Green Infrastructure Fee addresses repayment of principal and interest on bonds issued under the State of Hawai'i Department of Business, Economic Development, and Tourism's Green Energy Market Securitization program and related financing costs.
- Earlier this year, the PUC approved the HECO Companies' request to recover its new demand response program costs through the Demand Response Adjustment Clauses ("DRACs"). There will be separate DRACs for residential and commercial and industrial customers. While the companies have proposed specific tariff sheets for the DRACs in the IRP/DSM tariffs, these sheets have not yet been approved.

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[26] A 2014 discussion by the PUC indicated that the ECACs address variable costs of energy associated with Purchased Power Agreements.

[27] A 2014 discussion by the PUC indicated that the capacity and other fixed contractual payments for Purchased Power Agreements were included in the PPACs.

Performance Metric System

The HECO Companies' performance metric system includes PIMs and reporting of various metrics. PIMs currently address performance in traditional service areas such as service reliability and call center performance as well as demand response and cost-effective renewable procurement.[28]

The service reliability PIMs feature metrics for SAIDI and SAIFI. These PIMs are asymmetrical and penalize the companies for reliability declines beyond 1 standard deviation from the target. The targets were based on the company's historical reliability performance and are updated upon issuance of a rate case order.

The customer service quality PIM focuses on a single metric, call center performance, as measured by the percentage of calls answered in 30 seconds. This PIM is symmetrical and allows for penalties or rewards outside of a dead band of +/-1 standard deviation from the target. The target is based on the company's historical call center performance.

Two noteworthy features of the HECO Companies' performance metric systems are the breadth of the metrics, and the requirement that HECO post these metrics on company-sponsored webpages as a type of scorecard.[29] The HECO Companies' reporting of metrics is divided into 8 categories, each of which is presented on a separate webpage. Table 2 lists the metrics the HECO Companies report as well as the webpage where it is reported. These metrics cover many important performance areas. There are not currently metrics for AMI, DSM, or DG Service Quality.[30] The Companies update the website quarterly.

The HECO Companies' websites show several advantages to providing scorecards of performance on a publicly available website. First, use of the website provides a greater opportunity to provide definitions of the metrics for the reader's benefit, as the Companies are no longer limited to readability issues on a few pages. The design of the websites, by having only one topic on each webpage, allows a focus on specific issues that are relevant to customers (e.g., a customer that is concerned that the HECO Companies' reliability is bad can see a page of metrics focused solely on reliability). The use of websites also enables the HECO Companies to report a broader array of metrics and to use a wider array of methods to communicate their performance, including graphs, tables, and comparisons between the three HECO Companies. The websites allow interested parties to download historical data or alternative versions of the metrics.

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[28] The demand response and cost-effective renewable procurement PIMs are discussed in a separate section below.

[29] The address to the HECO Companies' website scorecard is https://www.hawaiianelectric.com/about-us/key-performance-metrics.

[30] The lack of DSM metrics is due to the transfer of the HECO Companies' DSM programs to a third-party administrator.

Table 2

Metrics Reported on HECO Companies' Website Scorecard

Webpage	Metric
Reliability	SAIDI normalized and non-normalized
Reliability	SAIFI normalized and non-normalized
Reliability	Customer Average Interruption Duration Index ("CAIDI") normalized and non-normalized
Reliability	Momentary Average Interruption Frequency Index ("MAIFI") normalized and non-normalized
Reliability	Emergency response time
Customer Service	Customer transaction survey results by call type (e.g., Customers who have billing inquiries, report trouble calls, or request a change in service)
Customer Service	Percentage of calls answered in 30 seconds ("Service Level")
Customer Service	Number of customer complaints by type and source (e.g., formal or informal complaints to the Commission, or escalated executive complaints)
Customer Service	Average percentage of bills that do not need to be rebilled or reprinted ("Billing Accuracy")
Customer Service	Percentage of meters read
Customer Service	Orders & appointments: time interval for connections/disconnections, meter re-read orders, percentage of appointments met by type of order
Power Supply & Generation	Independent power producer ("IPP") generation as a percentage of total net generation, by fuel type
Power Supply & Generation	Weighted equivalent availability factor
Power Supply & Generation	Weighted equivalent forced outage rate – demand
Power Supply & Generation	Weighted equivalent forced outage factor
Power Supply & Generation	Losses & unaccounted for energy
Renewable Energy	RPS compliance: percentage of sales that are renewable by source
Renewable Energy	System renewable energy: percentage of total net generation that is renewable, excluding DG
Renewable Energy	Total renewable energy: percentage of total generation that is renewable, including DG
Renewable Energy	Amount of renewable energy curtailment expressed both as percentage of available IPP curtailable energy and percentage of available IPP curtailable energy and all other renewable generation; also provided by category
Renewable Energy	Number of net energy metering customers and capacity in net energy

	metering program
Renewable Energy	Amount of energy exported by net energy metering program participants
Financial	Achieved ROE for ratemaking purposes
Financial	Credit ratings from Fitch, Moody's and Standard & Poor's rating services
Safety	Total case incident rate: number of work-related injuries and illnesses per 200,000 hours worked
Safety	Lost time rate: number of work-related injuries or illnesses that cause employees to be unable to work their full assigned shift per 200,000 hours worked
Safety	Number of public safety incidents connected to utility's operations or service that result in hospital admission or fatality
Rates & Revenues	Average revenue per kWh by rate schedule
Rates & Revenues	Contributing cost components to customer rates broken into fuel, purchased power, O&M, return, depreciation, taxes, revenue decoupling adjustments, public benefits surcharge, and other components
Rates & Revenues	Allowed recovery of fuel & purchased energy costs
Rates & Revenues	Number of customers on TOU rates (itemized by EV and non-EV customers)
Emerging Technologies	Cumulative customer load enrolled in demand response programs, number and duration of demand response events
Emerging Technologies	Energy storage: utility and IPP storage capacity (MW and MWh)

Some PIMs have also been approved which provide a positive incentive for capex containment.

- The DR Portfolio PIM provides the Companies with 5% of the aggregate annual contract value of the DR portfolio acquired, enrolled, and operational by the end of 2018. This incentive is capped at $500,000. These amounts will be recovered with traditional PIM financial incentives in the PIM provision tariff, however, the proposed integration into the PIM provision tariff has yet to be approved by the PUC.[31]
- The PUC has recently approved a PIM for Renewable PPAs. This allows the HECO Companies to share 20% of the savings for renewable PPAs. Savings are calculated as the amount by which levelized cost is below the PUC's per-kWh cost benchmarks.[32] These benchmarks

[31] The PIM provision tariff sheet outlines the Companies' PIMs, including metrics, targets, and financial incentives. PIMs addressed in this tariff include those for reliability and customer service.

[32] Two benchmarks were established. For projects that included renewable energy and storage, the benchmark was 11.5 cents per kWh, while projects excluding storage had a benchmark of 9.5 cents per kWh.

were established based on recent per-kWh costs of renewable projects in Hawaiʻi. The incentive would be calculated by multiplying the amount by which cost per kWh is below the benchmark by the forecasted first year energy production from the project up to a $3,500,000 cap. To encourage the HECO Companies to quickly pursue further cost-effective renewable PPAs, the PUC subsequently approved a second renewable PPA PIM, which allows the HECO Companies to share 20% of the estimated savings for renewable PPAs filed with the PUC by the end of 2018 up to a cap of $3 million. For renewable PPAs filed with the PUC through March 2019, the Companies' share of cost savings would be reduced.

Appraisal

Incentives

Appraisal of the need to reform the PBR frameworks of the HECO companies should consider structural and command and control provisions of HECO's regulatory system as well as the current PBR provisions. Several structural and command and control provisions reduce the need for PBR and affect the package of reforms that are needed. For example, there are aggressive RPS and EEPS targets in Hawaiʻi, and conservation programs are the charge of an independent agency. HECO is already engaged in integrated system planning and competitive bidding for power supplies.

It should also be noted that the regulatory systems of the HECO Companies already have numerous PBR provisions that strengthen incentives to pursue policy goals, including the embrace of DERs and the containment of capex. These provisions include multiyear rate plans, revenue decoupling, and an unusually elaborate performance metric system that includes pilot PIMs for demand response and renewable power purchases. Cost trackers further reduce any disinclination the Companies may in theory have to purchase power and pursue demand response. While improvements can be made in all of these provisions, few regulatory systems in the United States have comparably sophisticated PBR provisions.

Notwithstanding the solid foundation for regulation that has been established, incentives to contain costs of generation fuel and emissions remain a salient concern in Hawaiʻi, as in virtually all American states. We are also concerned with the Companies' incentives to obtain power from DGS customers at the right times and places and on reasonable terms. This is a critically important dimension of the Companies' performance going forward. Capex containment incentives are not notably weak but are not as strong as those in unregulated markets.

Risk

A reasonable opportunity for a utility to earn revenue commensurate with the efficient cost of service was noted in Section 2 to be an important goal of regulation. A regulatory system that does not provide this opportunity subjects the utility to unfair risk and raises the rate of return they must pay to access capital markets.

HECO's regulatory system has some features that contain risk, including revenue decoupling, forward test years, a RAM indexed to inflation, and several cost trackers. However, operating risk is still substantial, for the following reasons.

- Rate cases take an unusually long time to process, and forward test years are not calibrated to recognize these delays.
- The RAM cap is not based on a solid foundation of mathematical reasoning and empirical research. A properly developed revenue cap index is a useful benchmark for appraising the reasonableness of the current RAM cap. No study has previously been presented in evidence in recent Commission proceedings which ascertains whether GDPPI is a reasonably compensatory RAM cap for the HECO companies.
- The RAM adjustment to rates does not occur until the middle of the following year.
- There is currently no Z factor in the revenue adjustment formula.
- The RPS and other policies will lead to the HECO Companies purchasing substantial additional amounts of power from IPPs via purchase power agreements.
- There is an outsized risk of stranded costs but no assurance that these costs will be recovered.
- The ability of the Companies to use their existing trackers to recover capex costs is unclear.
- The ECRC needlessly exposes HECO to the risk of oil price fluctuations.
- Recent Hawaiʻi regulation has, as noted above, controversially called for a severance of the direct link between utility revenue and capital cost.
- The Companies have failed to earn their target ROEs in most recent years. Credit ratings are low by utility industry standards.

Conclusions

A review of HECO's regulatory system prompts the following conclusions.

- Regulation of the HECO Companies is headed in the right direction and sweeping changes are not warranted at this time. Improvements can nonetheless be made, and these can build on features of the current regulatory systems.
- The Companies are subject to needless operating risks. Particular concerns include the RAM cap, its lagged implementation, rate case delays, stranded costs, and the exposure to oil price risk in the ECRC. Reductions in needless risk can facilitate greater use of PBR in more productive areas where it can have more impact on incentives.

6.3 Indicated Regulatory Reforms

Our analysis points to a number of sensible reforms to the regulatory systems of the HECO Companies. If separate regulation of the three companies continues, the reforms need not be the same for each company.

Command and Control

Several command and control provisions of the HECO Companies' regulatory system can be constructively strengthened. Integrated grid planning under Commission oversight has already been proposed. Ex ante approval of innovative pilot programs can be granted to encourage innovation during MRPs.

Reduction of the stranded cost risk that the Companies face can contain the cost of obtaining funds in capital markets and reduce the disincentive to embrace an accelerated transition to renewable resources that would otherwise raise this risk. Continuing careful oversight of rate designs and terms of DGS customer compensation for power surpluses is needed to ensure that they leverage technological change and realize their potential to aid the cost-effective integration of intermittent renewables.

PBR

Multiyear Rate Plan

The multiyear rate plans of the HECO Companies can be upgraded in several ways to further streamline regulation and strengthen their incentives to contain costs of capital and other base rate inputs. For example, plan terms can be increased (e.g., to four or five years). As discussed further in Section 7, this will require new RAMs and/or RAM caps because the current RAM caps have been found to be under-compensatory. A more appropriately designed revenue cap index might make it unnecessary to have two RAM formulas. A Z factor and more timely (e.g., January 1) implementation of allowed revenue escalation would also make a longer plan term more feasible.

Earnings sharing can be scaled back or eliminated to strengthen performance incentives and facilitate marketing flexibility. However, ESMs can moderate the risks of longer plan terms. If ESMs are retained, a range of ROEs called a dead band can be established in each mechanism wherein all surplus earnings accrue to the Company.

Efficiency carryover mechanisms can be added to plans. These need not be as complicated as those in Australia and New Zealand. For example, in the next rate case HECO could be permitted to keep 10% of the benefit if the test year revenue requirement is below that commensurate with the RAM cap.[33]

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[33] Suppose, for example, that a hypothetical utility's base revenue requirement is $ 1 billion dollars in the first year of a five-year plan and that a revenue cap index happens to produce 4% escalation every year. The revenue requirement addressed by the index will then be about $1.170 billion in the last plan year. If the proposed

Additional Metrics and PIMs

Even if the incentives generated by the MRPs are strengthened by means like those detailed above, additional metrics and PIMs merit consideration in several areas where there are incentive holes in the current regulatory system. These areas include local and systemwide peak load management and the acquisition of DGS customer power surpluses at the right times and places.

Customer service PIMs could be expanded to include one or more service dimensions of particular interest to DGS customers. An example is the timeliness of DGS connections. PIMs for demand response and DGS power procurement can both be designed to share estimated net benefits, although this can involve complex calculations.

EOT loads reduce greenhouse gas emissions but revenue decoupling weakens incentives to encourage them. EOT can be encouraged by targeted PIMs. Alternatively or in addition, margins from EOT loads can be shared mechanistically.

Incentivized Cost Trackers

The MPIR tracker can be more incentivized. For example, cost reductions from capex underspends can be shared between each Company and its customers in a certain range and/or accrue entirely to the Company in a certain range.

Targeted Encouragement of Strategic Inputs

Usage of several kinds of strategic inputs can be targeted for encouragement.

- In addition to costs of purchased power and peak load management, these could include costs of innovative capital (e.g. smart grid) and O&M inputs which have the potential to lower total capex. An example here would be expenses for software services that take the place of software purchases.
- Incentives to incur O&M (e.g., DR portfolio) expenses that reduce capex, generation fuel, or external costs could be bolstered by capitalizing them, adding a rate of return premium, and/or awarding the Companies a share of them as a management fee.
- A good argument can still be made to track costs of capex required to accommodate increased reliance on renewable resources.
- A "totex" approach to setting revenue requirements merits consideration in the longer term.

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revenue requirement is less than $1.170 x 1.04 = $1.217 billion for the first year of the next plan, the utility would get to keep a share of the cost savings.

6.4 Conclusions

Regulation should maximize the net value of utility operations and allocate the value stream fairly. Various tools are available to regulators to produce good outcomes. The toolkit includes periodic rate cases with prudence reviews, careful oversight of rate designs and terms of compensation for DGS customer power surpluses, integrated grid planning, revenue decoupling, multiyear rate plans, and performance metric systems. Performance incentive mechanisms plug holes in the incentive structure but must be carefully designed to avoid undue risk and regulatory burden. The appropriate performance metric system depends greatly on other features of a utility's regulatory system.

The HECO Companies operate under unusually sophisticated regulatory systems that include integrated grid planning, multiyear rate plans, revenue decoupling, and performance metric systems. The Company is also subject to aggressive renewable portfolio and energy efficiency portfolio standards. DSM is pursued by an independent agency and reliance on renewable resources is high and growing. Rate designs are closely and thoughtfully regulated. There is no need for radical regulatory reform.

Worthwhile reforms to the regulatory system of the HECO Companies should nonetheless be considered in various areas. These include integrated grid planning and improved multiyear rate plans. There are some new performance dimensions and areas of weak incentives which new performance incentive mechanisms can address. Expansion of the performance metric system should nonetheless be careful and methodical. Operating risk can be reduced in several ways that will not weaken performance incentives.

7. Appraising the RAM Cap

7.1 Introduction

We have noted that the HECO companies are vertically integrated electric utilities that are currently subject to caps on the escalation of their allowed base rate revenue between rate cases. The RAM cap of each company has the following formula.

growth Allowed Base Revenue = growth GDPPI. [1]

Here GDPPI is the U.S. government's gross domestic product price index. Supplemental base rate revenue is potentially available to each Company via a MPIR tracker and other trackers.

The Companies have asked PEG to consider whether these RAM caps are reasonable and, if not, to consider alternative RAM caps. We discuss here the latest results of our research on this issue.

7.2 Analysis

Basic Results of Index Logic

Cost theory reveals that growth in the cost of a company is the sum of its input price inflation and growth in its operating scale less growth in its productivity.

growth Cost = growth Input Prices – growth Productivity + growth Scale. [2]

Here *Scale* measures growth in the company's operating scale. In an application to the cost of base rate inputs of vertically integrated electric utilities, which provide generation as well as power delivery services, *Scale* should be a multidimensional index. Growth in *Scale* could, for example, be a weighted average of growth in generation capacity, generation volume, and the number of customers served.

Sensible weights for such a scale index can be obtained from econometric research on the drivers of VIEU cost. The elasticity of cost with respect to growth in each scale variable can be estimated econometrically.[34] The weight for each scale variable can then be larger the larger is its cost elasticity.

Relation [2] can be restated as

growth Cost = growth Input Prices – growth Productivity + growth Scale
+ growth GDPPI – growth GDPPI
= growth GDPPI – [*growth Productivity* + (*growth GDPPI - growth Input Prices*)]
+ growth Scale. [3]

[34] The elasticity of cost with respect to a scale variable is the percentage change in cost with respect to a small change in the value of the variable.

Relation [3] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation. The difference between GDPPI and utility input price inflation may be termed the "inflation differential."

This result provides the basis for the following revenue cap index

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Scale}^{Utility}. \quad [4a]$$

Here X, the X factor, has the following formula.

$$X = \textit{trend } \overline{\textit{Productivity}}^{Industry} + (\textit{trend } \overline{\textit{GDPPI}} - \textit{trend } \overline{\textit{Input Prices}}^{Industry}) + \textit{Stretch} \quad [4b]$$

Relation [4b] states that the X factor should reflect the average productivity trend ($\textit{trend } \overline{\textit{Productivity}}^{Industry}$) and inflation differential of a group of utilities. The scale index in [4a] should measure growth in the operating scale of the subject utility. The productivity trend of the industry should be measured using a consistent scale index. The inflation differential matters chiefly because GDPPI has in many past years understated the input price trends of electric utilities because it has historically reflected the brisk productivity growth of the economy.

Alternative Formulation

Consider now as an aside that the GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services.[35] It can then be shown that the trend in the GDPPI is well-approximated by the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{trend Productivity}^{Economy}. \quad [5]$$

The formula for the X factor can then be restated as

$$X = [(\textit{trend } \overline{\textit{Productivity}}^{Industry} - \textit{trend Productivity}^{Economy}) + (\textit{trend Input Prices}^{Economy} - \textit{trend } \overline{\textit{Input Prices}}^{Industry})]. \quad [6]$$

Here the first term in parentheses is called the "productivity differential". The second term in parentheses is called the "*input price* differential" and is different from the *inflation* differential in [4b]. Relation [4b] is simpler and equally applicable. Relation [6] is nonetheless notable because it has been the basis for the design of several approved X factors in PBR plans.

Revenue Cap Index Precedents

Revenue cap indexes of the general form detailed in relation [4a] have been approved for several North American energy utilities. Most commonly, growth in allowed revenue equals inflation – X + customer growth. Companies that have operated under this general revenue cap formula include Southern California Gas in California, Enbridge Gas Distribution in Ontario, and ATCO Gas in Alberta. The

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

Régie de l'energie in Québec has ruled that Hydro-Québec Distribution and Gaz Metro will prospectively operate under such indexes. None of these companies are VIEUs. In British Columbia, FortisBC and FortisBC Energy also have revenue requirement escalators that include inflation, productivity, and customer growth terms.

Suppose, now, that the revenue cap index lacks a scale index. The terms of [4a] could be rearranged if desired as

$$growth\ Revenue^{Allowed} = growth\ GDPPI + A \qquad [7]$$

where $A = growth\ Scale^{Expected} - X$. It can be seen that parameter *A* should increase allowed revenue growth to the extent that *X* is negative and expected growth in operating scale is positive. Parameter *A* is potentially useful for measuring the bias in the current RAM cap.

Application to the HECO Companies

To develop a revenue cap index for the HECO Companies, a rigorous and thorough approach would be to use the latest available data (e.g., through 2017) from the Federal Energy Regulatory Commission ("FERC") and other reputable sources to 1) develop a scale index using econometric research on VIEU cost to identify scale variables and their cost elasticities and 2) calculate the average productivity trend and inflation differential of the sampled utilities.[36] A stretch factor (typically 0.20%) could in principle be added to X to share with customers the benefit of productivity growth that is superior to the industry norm.

An X factor could instead be calculated using a simpler "Kahn Method" exercise. This method was developed by former (and deceased) Cornell University regulatory economist Alfred Kahn and is still used by the Federal Energy Regulatory Commission ("FERC") to set the X factors of interstate oil pipelines. In an application to the HECO Companies we would calculate trends in the cost of base rate inputs of a sample of VIEUs using FERC Form 1 data and traditional cost accounting and then solve for the value of X which would have caused the trend in VIEU cost to equal the trend in a revenue cap index with a formula like [4a] on average. This analysis would exclude costs that are likely to be addressed by trackers and riders in the Companies' regulatory system. Note that the X factor resulting from such a calculation reflects the inflation differentials of sampled utilities as well as their productivity trends. Stated differently, the X factor would reflect the input price and productivity differentials of utilities.

One complication with this analysis is that the HECO companies are subject to MPIR trackers. These have chiefly been used to date for costs of new renewable-related generation capacity. One way to finesse this complication is by not escalating the revenue requirement for growth in generation capacity or volume. At the extreme, the scale index could be removed from the RAM cap formula in its entirety. However, it is not necessarily reasonable to deny HECO the growth in revenue requirement that it needs to fund necessary cost growth. Multiyear rate plans in several Canadian provinces feature

[36] We could, alternatively, use the same data to calculate input price and productivity differentials consistent with relation [6].

rate or revenue cap indexes and provide supplemental revenue for capital cost growth without adjusting other plan terms.

7.3 Empirical Research for HECO

Overview

PEG has undertaken three kinds of empirical research to consider alternative RAM caps for the HECO companies. All three tasks used a sample of good data for 45 major investor-owned American VIEUs. Data on the cost and operating scale of these utilities were obtained from their FERC Form 1 and U.S. Energy Information Administration filings.

Costs were excluded from the research which were not pertinent to the design of a RAM cap for the HECO Companies either because the Companies do not incur these costs or because these costs will likely be addressed using trackers. The excluded costs included those for the following inputs:

- Generation fuels, purchased power, and other power supply expenses
- Other nuclear and hydroelectric generation inputs
- Pensions and benefits
- Taxes
- Load dispatching, transmission by others, and miscellaneous transmission expenses
- Customer service and information inputs.[37]

Development of a Scale Index

Our first task was to develop a scale index. We estimated the parameters of an econometric model of the cost of VIEU base rate inputs. In this model, capital cost was calculated using the geometric decay method that we used in our previous productivity research for HECO. Total cost was divided by the input price index to enforce a prediction of economic theory that 1% growth in the prices of all inputs raises cost by 1%. This is thus a “real” cost model.

The values of cost and all business condition variables in the cost model were logged. This means that the parameter estimates were also estimates of the elasticities of cost with respect to the scale variables. The estimation was undertaken with the R statistical programming software using a procedure that corrected for autocorrelation and groupwise heteroscedasticity.

Results of this research can be found in Table 3. It can be seen that we identified seven business condition variables with statistically significant and plausibly-signed parameter estimates.[38] These include the following four scale variables:

[37] For many utilities, this cost category is dominated by DSM program expenses.

Table 3

Econometric Model of VIEU Total Cost

EXPLANATORY VARIABLE	ESTIMATED COST ELASTICITY	T-STATISTIC	P-VALUE
Number of Customers* **	0.581	33.191	0.000
Generation Volume* **	0.121	9.234	0.000
Generation Capacity* **	0.118	7.648	0.000
Transmission Line Miles* **	0.097	9.834	0.000
Percentage of Capacity Scrubbed***	0.097	8.736	0.000
Percentage Coal and Heavy Fuel Oil***	0.279	12.138	0.000
Number of Gas Customers***	-0.092	-7.305	0.000
Constant***	20.109	1034.232	0.000
Trend***	0.003	3.904	0.000
Adjusted R-squared	0.950		
Sample Period	1996-2017		
Number of Observations	990		

***Estimate is significant at the 99.9% confidence level

- Generation capacity
- Generation volume
- Transmission line miles
- Number of retail customers.

The explanatory power of the model is quite high.

[38] The model also contained a trend variable with a slightly positive parameter estimate.

Table 4 shows how the econometric elasticity estimates can be used to calculate the weights for a scale index. It can be seen that the largest weight by far was the 63.3% weight assigned to the number of customers served. Generation volume had a weight around 13.2% whereas generation capacity had a 12.9% weight and transmission line miles had a 10.6% weight.

Table 4

Cost-Elasticity Weights

(derived from Table 3)

SCALE DRIVER	ESTIMATED COST ELASTICITY[1]	COMMENSURATE WEIGHT[2]
Number of Retail Customers	0.581%	63.335%
Generation Volume	0.121%	13.176%
Generation Capacity	0.118%	12.906%
Transmission Line Miles	0.097%	10.583%
		$\sum$ = 100%

[1]Defined to be the associated rise in cost with a 1% increase in scale. For example, PEG's econometric research finds the cost elasticity with respect to customers to be 0.581%, i.e., a 1% increase in number of customers is associated with a 0.581% rise in cost.

[2]The formula is the cost elasticity divided by the sum of all cost elasticities.

Calculating X Using the Kahn Method

We postulated a hypothetical generic revenue cap index like that in [4a] with the following form:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Scale}^{Utility}. \quad [8]$$

The scale index used the four scale variables and elasticity weights discussed above. 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 calculated the value of X that would cause the trends in the costs of our sampled VIEUs to equal the trends in the hypothetical revenue cap indexes on average over the sample period. The full sample period we considered was the twenty-one-year 1997-2017 period. We also considered the results for shorter and more recent periods.

Results of this exercise can be seen in Table 5 and Figure 7. It can be seen that, for all sample periods considered, the average annual growth in cost was considerably more rapid than the average annual growth in the GDPPI. The average annual growth in the scale index was not large enough to close the gap. Thus, the X factor must be negative if the hypothetical revenue cap indexes are to track historical VIEU costs on average. Using the scale index, the Kahn X factor was -1.28% for the full 1997-

Table 5

U.S. VIEU Kahn X Factor Calculations[1,2]

	Operating Scale							Kahn X Factors	
Year	Retail Customers	Generation Capacity	Generation Volume	Transmission Line Miles	Scale Index[3]	Inflation[4]	Total Cost	Using Scale Index	Using Customers
	[A]	[B]	[C]	[D]	[E]	[G]	[F]	[E+G-F]	[A+G-F]
1997	1.80%	-0.29%	3.70%	0.19%	1.61%	1.71%	8.40%	-5.08%	-4.89%
1998	1.92%	0.54%	7.41%	0.45%	2.31%	1.08%	3.63%	-0.23%	-0.63%
1999	1.40%	-2.04%	1.32%	0.32%	0.83%	1.42%	-3.25%	5.50%	6.07%
2000	2.07%	-1.09%	4.58%	-1.99%	1.56%	2.25%	5.91%	-2.10%	-1.60%
2001	1.51%	2.05%	-1.95%	0.02%	0.96%	2.26%	3.42%	-0.20%	0.35%
2002	1.40%	6.72%	-1.46%	0.11%	1.57%	1.52%	3.24%	-0.15%	-0.32%
2003	1.33%	3.34%	-0.47%	0.30%	1.25%	1.98%	1.06%	2.16%	2.25%
2004	1.45%	0.76%	0.35%	-0.48%	1.01%	2.71%	3.46%	0.27%	0.71%
2005	1.51%	4.07%	2.40%	-0.30%	1.77%	3.17%	3.99%	0.94%	0.69%
2006	0.20%	4.49%	-0.54%	-1.61%	0.46%	3.02%	4.30%	-0.82%	-1.09%
2007	1.40%	2.10%	5.19%	1.90%	2.04%	2.63%	6.50%	-1.83%	-2.47%
2008	1.04%	3.10%	0.19%	0.68%	1.15%	1.91%	4.54%	-1.48%	-1.59%
2009	0.60%	1.32%	-9.33%	1.24%	-0.55%	0.78%	3.32%	-3.09%	-1.94%
2010	0.52%	2.96%	9.30%	0.85%	2.03%	1.22%	9.83%	-6.57%	-8.08%
2011	0.44%	0.61%	-2.82%	0.60%	0.05%	2.04%	2.18%	-0.08%	0.31%
2012	0.59%	2.02%	-1.25%	1.21%	0.60%	1.82%	2.93%	-0.51%	-0.52%
2013	0.78%	0.11%	2.97%	-0.25%	0.87%	1.60%	4.29%	-1.82%	-1.91%
2014	0.81%	2.33%	1.92%	1.67%	1.25%	1.78%	5.97%	-2.94%	-3.38%
2015	1.02%	-0.48%	-4.25%	0.58%	0.08%	1.06%	3.43%	-2.29%	-1.36%
2016	1.08%	-0.56%	-1.65%	1.47%	0.55%	1.31%	6.73%	-4.87%	-4.34%
2017	0.85%	-0.06%	-1.63%	-0.16%	0.30%	0.89%	2.82%	-1.62%	-1.07%
Average Annual Growth Rates									
1997-2017	1.13%	1.52%	0.67%	0.32%	1.03%	1.82%	4.13%	**-1.28%**	**-1.18%**
2002-2017	0.94%	2.05%	-0.07%	0.49%	0.90%	1.84%	4.29%	**-1.54%**	**-1.51%**
2007-2017	0.83%	1.22%	-0.12%	0.89%	0.76%	1.55%	4.78%	**-2.46%**	**-2.39%**

Notes:

All values are an average of data gathered from a nationally-representative sample of 45 U.S. VIEUs.

[1]Costs and scale drivers inapplicable to HECO are excluded from this analysis. These include conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity and volume.

[2]All values shown are logarithmic growth rates.

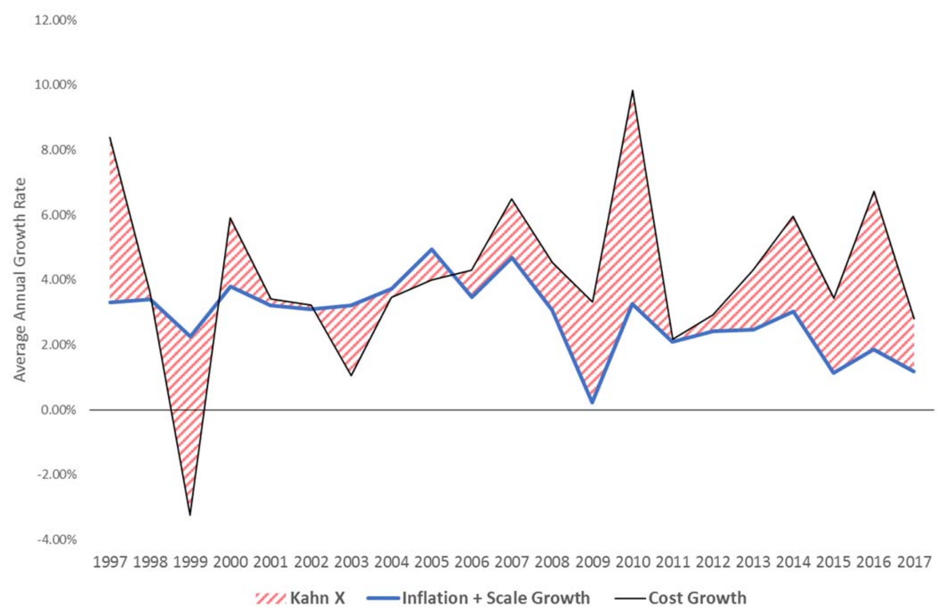
[3] [E] = 63.34% x [A] + 12.91% x [B] + 13.18% x [C] + 10.58% x [D]. The scale index is a cost-elasticity-weighted average of customers (63.34%), transmission line miles (10.58%), generation capacity (12.91%), and generation volume (13.18%). The weights are obtained from econometric cost research customized for HECO, presented in Table 3.

[4]Inflation is Gross Domestic Product Price Index (GDPPI).

2017 sample period and -1.54% for the more recent 2002-2017 sample period. A similar value for X was obtained using the number of customers as the scale escalator in the hypothetical revenue cap indexes.

Figure 7

Kahn X: How Cost Growth Outpaces Inflation + Scale Growth



Decomposing X

Our third task was to decompose the X factor. For each VIEU in the sample we calculated an index of the trends in prices of base rate inputs. In these calculations, we used a formula designed to mimic the traditional cost of service treatment of capital cost. We used these indexes to calculate the inflation differential for each company as detailed in relation [4b] above.

Results of this exercise can be found in Table 6. It can be seen that growth in the industry input price index was substantially more rapid on average than the growth in the GDPPI. Over the full 1997-2017 sample period, for example, industry input price growth exceeded GDPPI growth each year by 0.99% on average. We conclude that the inflation differential is the main source of the negative X factor values that we calculated.

Implications for the HECO Companies

Let's consider now the implications of this research for the HECO Companies. Suppose first that HECO had a revenue cap index like that in [8].

$$growth\ Allowed\ Base\ Revenue^{HECO} = growth\ GDPPI - (X^{Kahn} + Stretch) + growth\ Scale^{HECO}. \quad [9]$$

This formula would clearly yield substantially more revenue for each Company than the current RAM caps.

Table 6

Decomposing the Kahn X Factor

Year	Kahn X Factor [A]	GDPPI [B]	Industry Input Price Growth [C]	X Explained by Choice of GDPPI [D] = [B] - [C]	X Explained by Productivity and Other Factors [E] = [A] - [D]
1997	-5.08%	1.70%	3.72%	-2.01%	-3.06%
1998	-0.23%	1.08%	3.98%	-2.90%	2.67%
1999	5.50%	1.42%	0.61%	0.81%	4.69%
2000	-2.10%	2.25%	5.71%	-3.46%	1.36%
2001	-0.20%	2.26%	2.04%	0.22%	-0.41%
2002	-0.15%	1.52%	1.98%	-0.47%	0.32%
2003	2.16%	1.98%	2.10%	-0.12%	2.28%
2004	0.27%	2.71%	2.33%	0.37%	-0.11%
2005	0.94%	3.17%	2.30%	0.87%	0.07%
2006	-0.82%	3.02%	2.89%	0.13%	-0.95%
2007	-1.83%	2.63%	3.08%	-0.45%	-1.38%
2008	-1.48%	1.91%	4.00%	-2.09%	0.61%
2009	-3.09%	0.78%	2.99%	-2.20%	-0.89%
2010	-6.57%	1.22%	3.01%	-1.79%	-4.78%
2011	-0.08%	2.04%	2.70%	-0.65%	0.57%
2012	-0.51%	1.82%	2.41%	-0.59%	0.08%
2013	-1.82%	1.60%	2.42%	-0.81%	-1.00%
2014	-2.94%	1.78%	2.46%	-0.68%	-2.26%
2015	-2.29%	1.06%	3.41%	-2.35%	0.06%
2016	-4.87%	1.31%	1.21%	0.10%	-4.96%
2017	-1.62%	0.89%	3.58%	-2.69%	1.06%
Average Annual Growth Rates					
1997-2017	-1.28%	1.82%	2.81%	-0.99%	-0.29%
2002-2017	-1.54%	1.84%	2.68%	-0.84%	-0.70%
2007-2017	-2.46%	1.55%	2.84%	-1.29%	-1.17%

Pacific Economics Group Research, LLC

If an adjustment is deemed necessary to take account of the supplemental revenue provided by the MPIR tracker, one candidate formula is

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} - (X^{Kahn} + \textit{Stretch}) + 0.633 \times \textit{growth Customers}^{HECO}. \quad [10]$$

This formula escalates revenue for customer growth but not for growth in generation volume, capacity, or transmission lines since growth in these scale variables might be funded by the MPIR. At the extreme, the Companies could be denied all benefit of growth in *Scale*. The formula would then be

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} - (X^{Kahn} + \textit{Stretch}). \quad [11]$$

Results would vary with the stretch factor and the sample period used to calculate X^{Kahn}. Assuming a 0.20% stretch factor and an X^{Kahn} of -1.28% based on results for the full sample period the alternative revenue cap indexes would be

$$\begin{aligned}\textit{growth Base Revenue}^{HECO} &= \textit{growth GDPPI} - (-1.28 + 0.20) + 0.633 \times \textit{growth Customers}^{HECO} \\ &= \textit{growth GDPPI} + 1.08 + 0.633 \times \textit{growth Customers}^{HECO}. \quad [12]\end{aligned}$$

or

$$\textit{growth Base Revenue}^{HECO} = \textit{growth GDPPI} + 1.08. \quad [13]$$

Negative X Factor Precedents

Negative X factors have been approved by some regulators. There are several precedents in Britain and Australia, where the ARMs of multiyear rate plans have a hybrid design in which an inflation-X formula is used but X reflects multiyear forecasts of cost and inflation. One example is found in the 2006 British Transmission Price Control Review Final Proposals where Ofgem approved an RPI+2 price control for electric transmission utilities "to ensure that revenues, and associated cash flows are aligned more closely to the rising trend of costs resulting from the substantial increase in investment envisaged over the 5-year period."[39]

In U.S. multiyear rate plans with indexed ARMs, X factors for retail services of gas and electric utilities typically reflect research on input price and productivity trends, and the inflation measure is typically an index of economy-wide inflation such as the GDPPI. Negative X factors have in this context chiefly reflected the sluggish growth in the GDPPI relative to industry input prices. Recollecting relation [6], we can state equivalently that negative X factors reflect a substantially negative productivity differential. An example of a negative X factor in a U.S. plan is that recently approved for the Massachusetts power distributor services of Eversource. The approved revenue cap index has the following formula:[40]

$$\begin{aligned}\textit{growth Allowed Base Revenue} = \textit{growth GDPPI} - [&(\textit{trend MFP}^{Industry} - \textit{trend MFP}^{Economy}) \\ &+ (\textit{trend Input Prices}^{Economy} - \textit{trend Input Prices}^{Industry})].\end{aligned}$$

[39] Ofgem, *Transmission Price Control Review Final Proposals*, December 2006, p. 7.

[40] A stretch factor term was addressed separately and made conditional on the trend in the GDPPI.

The X factor thus includes a productivity differential term (*trend MFP*^{Industry} – *trend MFP*^{Economy}) and an input price differential term (*trend Input Prices*^{Economy} – *trend Input Prices*^{Industry}). In the case of Eversource, the productivity differential was -1.35% and the approved input price differential was -1.29%.[41] A witness for a consumer advocate also supported a negative X factor despite his finding of a positive MFP trend.

The FERC has also approved three consecutive inflation-X multi-year rate plans for interstate oil pipelines which feature a negative X factor. These X factors were determined using the Kahn X factor methodology and pipeline industry data. The current oil pipeline index escalates prices by the Producer Price Index for Finished Goods plus 1.23%, implicitly indicating an X factor of -1.23%. The prior oil pipeline index escalated prices by the Producer Price Index for Finished Goods plus 2.65%, indicating an X factor value of -2.65%.

[41] The regulator increased the X factor to -1.56% to reflect the removal of some capex commitments that had been proposed by Eversource.

Appendix

A.1 Provisions for Supplemental Capital Revenue

Ontario

Incentive Regulation Mechanisms

The Ontario Energy Board ("OEB") regulates more than 60 power distributors of varying sizes. Most of these distributors operate under PBR plans called incentive regulation mechanisms ("IRMs"). In these plans, rates are initially set based on rate applications that include a distribution system plan ("DSP"). Rates in later plan years are escalated by price cap indexes with I-X formulas. The X factor for each utility is the sum of a common base productivity trend and a custom stretch factor that reflects the results of a statistical benchmarking study that is updated annually. The base productivity trend is the historical MFP trend of a power distributor peer group.

Distributors have several options for obtaining supplemental capital revenue. One option is the capital module approach. This approach is designed to address situations where the distributor needs supplemental funding for capex in one or two years of the MRP term. There are two types of capital modules available: Advanced Capital Modules ("ACMs") and Incremental Capital Modules ("ICMs"). An ACM may be requested only during rate cases to address projects outlined in the distributor's system plan, while an ICM may be requested between rate cases to address projects not included in a distributor's DSP, for projects which have increased substantially in their size and scope since the approval of the system plan, and for those projects whose eligibility could not be determined during the rate case.

For either type of capital module, distributors must demonstrate that the capex driving the supplemental funding request is eligible, prudently incurred and the most cost-effective option for ratepayers, and material. Distributors overearning by more than 300 basis points cannot request a capital module.

The amount of capex needed must exceed a capex-to-depreciation-expense materiality threshold defined by the OEB and clearly have a significant influence on the operation of the distributor. The threshold is applied on an aggregate basis. Individual projects must also not be so minor as to be immaterial.

If a project qualifies for the ICM, recovery of amounts approved under the ICM is realized via rate riders. Distributors who receive approval for rate relief through an ICM are required to report their actual capex annually. Cost overruns are reviewed for prudence in rate rebasing proceedings. If the overrun is prudently incurred, the amount will be included in rates. Underspends will result in refunds to ratepayers.

The second option for Ontario distributors to request supplemental funding for capex is through a Custom Incentive Rate-setting ("Custom IR") plan. This option is designed for distributors that expect to undertake large capital projects over several years. With a Custom IR plan, many existing MRP provisions are replaced with options that are better suited to meet the distributor's capex need. This option allows distributors to develop MRPs based on forecasts of total O&M and capital spending. These forecasts should be informed by the OEB-sponsored productivity and benchmarking analyses. In several cases, this has taken the form of the distributor proposing an attrition relief mechanism based on the following formula:

$$I - X + C.$$

Here C is the supplemental annual rate or revenue growth needed to fund proposed capital cost growth. X is fixed for the plan term as the sum of the base productivity trend and a stretch factor supported by benchmarking evidence. To allay concerns of distributors overestimating cost and capex, Custom IR plans have in several instances included earnings sharing mechanisms and mechanisms to return the revenue requirements of capex underspends to customers at the end of the plan term.

Due to the high cost of developing and reviewing a Custom IR plan, the Ontario Energy Board has mandated that Custom IR plans have a minimum 5-year term. The cost of developing these plans has largely limited their application to the largest Ontario power distributors.

British Columbia

In 2014 the British Columbia Utilities Commission ("BCUC") approved a return to PBR for FortisBC Energy (formerly Terasen Gas) and FortisBC (formerly West Kootenay Power) after several years of more traditional regulation. Unlike PBR plans in many jurisdictions, these plans escalate budgets for O&M expenses and certain capital *expenditures* with separate formulas that are based on inflation and the growth of operating scale less an X factor. The FortisBC plan has one formula for capex which features the number of customers as the scale escalator. FortisBC Energy has one formula for growth-related capex and a second formula for sustainment and other capex. These formulas use the service line additions and the number of customers, respectively, as the scale escalators.

All of these index formulas are designed to escalate the allowed capex of projects that are smaller, more routine, and predictable. Capital costs for projects that are larger, more unusual in nature, and less predictable are tracked, along with the cost of all older plant. Projects that have been approved for capital cost tracking to date include FortisBC Energy's biomethane projects, FortisBC's deployment of AMI, and both companies' capitalized pensions and other post-employment benefits.

A substantial effort was undertaken to determine tracker eligibility criteria for capex.[42] This effort extended beyond the initial PBR proceeding with a decision reached in 2015, more than a year after the PBR plan started. The BCUC approved materiality thresholds for levels of eligible capex based on the updated Certificate of Public Convenience and Necessity materiality thresholds of $20 million for

[42] The BCUC refers to these criteria as capital exclusion criteria, meaning exclusion from formulaic escalators.

FortisBC and $15 million for FortisBC Energy for individual projects.[43] The BCUC rejected proposals for additional tracker eligibility criteria.

This decision also addressed several concerns about possible gaming and double counting issues. The companies are required to show in each capital tracker application that the eligibility criteria had not been met by a combination of smaller projects that would normally be funded by the index-based escalators. Individual application proceedings will include an opportunity for the impact of the project on O&M expenses to be addressed.

Alberta

The Alberta Utilities Commission developed generic MRPs to apply to the province's electricity and gas distributors. In these plans, rates or revenues per customer are escalated by indexes with I-X formulas. The X factor for each utility is the sum of a common base productivity trend and stretch factor. Concerns about ensuring that the Alberta distributors have sufficient funding for capex have led to provisions for supplemental funding in both generations of MRPs approved to date.

The current MRPs allow for two methods by which distributors may obtain supplemental funding based on the kind of capex. Capital cost tracker mechanisms may be requested to provide supplemental funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[44] Distributors must also show that this capex resulted in a revenue requirement impact that exceeded a materiality threshold of 4 basis points of ROE.

Supplemental funding for all other eligible capex is provided by a mechanism known as K-bar. K-bar provides supplemental funding on an aggregate basis. A base K-bar value was established for the first year of the plan based on recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, which were not funded by base rates. K-bar values in subsequent years are escalated by the growth in the attrition relief mechanism and billing determinants.

A.2 Z Factors

Z factors were noted in Section 5.3 to be typical components of approved multiyear rate plans. A Z factor adjusts revenue for miscellaneous hard-to-foresee events impacting utility earnings. These revenue adjustments may in principle be positive or negative.

Many MRPs have explicit eligibility requirements for Z-factor events. Here is a typical list of requirements.

<u>Causation</u>: The expense must be clearly outside of the base upon which rates were derived.

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[43] FortisBC Energy's biomethane projects were not required to meet this threshold in order to have the projects' costs tracked.

[44] In the first generation of PBR plans, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

Materiality: The cost must have a significant impact on the finances of the utility. Materiality can be measured based on individual events or the cumulative impact of events. Some plans have materiality thresholds of both kinds.

Outside of Management Control: To qualify for Z-factor treatment, the cost must be attributable to some event outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

Other potential criteria for Z factors are that the cost or benefit must be measurable and specifically affect the utility industry as opposed to the broader economy. Some common examples of Z factors are changes in tax laws, accounting standards, governmental mandates, and catastrophic events such as hurricanes and wildfires.

One of the primary rationales for Z-factor adjustments is the need to adjust revenue for the effect of changes in tax rates and other government policies on the company's cost. Absent such adjustments, policymakers can adopt new policies that increase the cost of a utility, confident in the knowledge that its earnings, rather than customer bills, will be affected. Another rationale for Z factors is to adjust for the effect of miscellaneous other external developments on utility costs that are not captured by the inflation and X factors. Z factors can potentially reduce operating risk and encourage more cautious behavior by government agencies, without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most of the benefits of MRPs. Disadvantages of Z factors include the fact that they can significantly raise regulatory cost, and the possibility that they may weaken utility incentives to mitigate the impacts of triggering events.

Materiality Thresholds

Many Z factor mechanisms have a specific pre-defined materiality threshold. This serves to reduce the incentive to file Z factors for minor events and the potential regulatory cost of Z factors.

Z factor materiality thresholds are often measured relative to the size of the utility's revenue requirement.[45] For example, the Ontario Energy Board, which regulates more than 60 power distributors, has a Z factor based on 0.5% of the distributor's revenue requirement for each Z factor requested. For distributors with a revenue requirement below $10 million, a floor of $50,000 was established. A cap of $1 million was established for distributors with revenue requirements in excess of $200 million.

In some cases, the materiality threshold is allowed to grow at the rate of inflation during an MRP. For example, the current MRP of Eversource Energy features an initial $5 million materiality threshold which is adjusted annually to reflect the growth in the GDPPI. Alberta power distributors have

[45] One exception to this is in British Columbia where the Z factors for the FortisBC companies only apply to O&M expenses. In this case, the materiality threshold is based on 0.5% of O&M expenses in the base year for the MRP.

a per Z factor event materiality threshold established at the level of 40 basis points of ROE in a base year escalated by the growth in the MRP's inflation measure less the X factor for each year of the MRP.

Materiality thresholds may also serve as a method to limit the recovery of Z factors. Where this is the case the amount of the Z factor is reduced by the amount of the materiality threshold. This reduction is sometimes referred to as a deductible. Deductibles usually only apply once during the life of an individual Z factor. For example, San Diego Gas & Electric's Z factor only provides compensation for amounts above the Z factor materiality threshold of $5 million per Z factor. If the Z factor applies for multiple years, the full amount incurred in subsequent years is included in the Z factor.

A.3 Recent U.S. Precedents for Policy PIMs

New York Overview

New York's Public Service Commission recently reconsidered its approach to regulating its 6 major power distributors in the Reforming the Energy Vision ("REV") regulatory proceeding. Empire State distributors have typically operated in recent years under MRPs featuring forecast-based attrition relief mechanisms with reliability and customer service PIMs. Concerns that distributors were intentionally underspending on capex led to the development of a "claw back" mechanism wherein the revenue requirement associated with capex underspends is deferred for the benefit of customers in the next rate case.

An important outcome of REV has been the addition of several policy metrics and PIMs called Earnings Adjustment Mechanisms ("EAMs"). Not every mechanism referred to as an EAM has financial rewards. Most EAMs are proposed by the distributors in their individual rate cases. EAMs approved to date have been components of approved settlements resolving rate cases. These EAMs have been supplemented by other performance incentives that encourage the development of non-wire alternatives ("NWAs"). These include modifications of the "claw back" mechanisms wherein distributors are not obliged to return capex underspends due to avoided projects resulting from successful NWAs. EAMs and NWA incentives have thus far been approved for Consolidated Edison ("Con Ed"), Central Hudson Electric & Gas ("Central Hudson"), and Niagara Mohawk Power.

Consolidated Edison

Most of Con Ed's EAMs were approved in its most recent rate case proceeding. There are EAMs for program achievement and outcomes. Program achievement EAMs are tied to the results of specific company programs (e.g., demand-side management), while outcomes EAMs are not. Targets for program achievement EAMs were set prior to the beginning of the MRP, while the targets for the outcomes EAMs are updated each year through a collaborative process.

The program achievement EAMs include PIMs for Con Ed's incremental energy efficiency and peak demand programs. The metric for the Energy Efficiency PIM were the incremental MWh of savings, while the metric for the peak demand program was the incremental system peak MW reduction. The basis for the targets and rewards related to the peak load management PIMs were unclear as the settlement merely outlines specific targets and reward levels for each year of the plan. The energy efficiency and peak demand programs have a second incentive provision that allows the company to amortize the cost of those programs over a 10-year period at Con Ed's pre-tax rate of return. Rewards from the PIMs are expensed.

The outcomes EAMs include PIMs for the MWh of DERs utilized and weather-normalized average use (separate metrics for residential and commercial customers) and a metric for the level of greenhouse gas emissions. EAMs for customer load factor and developer satisfaction with DG interconnections are still under development.

There is also a DER utilization PIM designed to encourage deployment of DERs in Con Ed's service territory. This mechanism rewards the company for both reducing customer reliance on grid-supplied electricity and increased beneficial electrification provided by the system. The performance metric is the sum of incremental (e.g., new DER deployment in a given year) annualized MWh of power production by community and rooftop solar, combined heat and power, and fuel cells, charging and discharge of battery storage, charging of electric vehicles and thermal storage, consumption by heat pumps, and reductions due to peak load management.[46]

The weather-normalized average use PIMs are designed to encourage efforts that will result in a decrease in average use or energy consumption beyond recent trends, defined as the 5-year 2010-2015 period. For each PIM, adjustments are made to the actual sales for each group to take account of weather and to remove sales resulting from beneficial electrification.[47] There are separate PIMs for residential customers, commercial customers, and multifamily and public customers. The metric for residential customers measures average use on a per customer basis, while the commercial metric measures average use as the total private employment in Con Ed's service territory as reported by the U.S. Bureau of Labor Statistics. The metric for multifamily and public customers has no denominator and merely reflects the change in sales to these customer classes.

A PIM for customer load factor has been frequently discussed, but no agreement has been reached at this point. The customer load factor metric, as originally envisioned, would address improvement in the load factor of poor load factor customers in a manner consistent with existing environmental goals. No specific definition of a poor load factor customer has been reached to date.

Stakeholders were able to agree on an EAM for greenhouse gas emissions after the rate case decision. This metric measures the total avoided kilograms of carbon dioxide emissions. This metric is calculated two ways, one being a bottom up approach and the other being a top down approach. The bottom up approach focuses on incremental measures each year to increase avoided carbon dioxide emissions using various forms of generation and storage including rooftop and community solar PV,

[46] Battery storage is counted for charging and discharging as it often charges off peak from low-emitting sources, and discharges on peak thereby reducing customer reliance on the grid. In addition, battery storage often provides reliability and resiliency benefits.

[47] Sales are not adjusted for incremental heat pumps, which are considered a form of beneficial electrification in the DER utilization PIM.

electric vehicles, heat pumps, battery storage, ice energy storage, electric heat pump water heaters, and wind energy. The top down metric relies on the annually published New York City Greenhouse Gas inventory rather than a measure solely reliant on distributed generation and storage. This metric will require further refinement to include modelling of the impact of various exogenous factors such as economic growth, demographic trends, and changes in generation technology. No targets or financial rewards have been attached to these metrics.

Each approved PIM has multiple target and reward levels for minimum performance, target performance, and maximum performance. The minimum performance threshold is the minimum level at which rewards may be earned. Performance below the minimum performance threshold will result in no rewards or penalties being applied. The maximum performance threshold is the level at which the maximum reward is earned (e.g., performance above the maximum threshold will not lead to increased rewards). Rewards for performance between the minimum performance threshold and targeted performance level, and between the targeted performance level maximum performance threshold are calculated linearly.

The overall rewards for each Program Achievement EAM and the total reward for the Outcomes EAMs in each year of the MRP at the minimum, target, and maximum performance levels were outlined in the settlement. The rewards for each performance level for the energy efficiency and peak demand reduction PIMs were defined at the outset of the plan, as were the total level of rewards for all the outcomes PIMs at each performance level. However, the share of the rewards for each outcome PIM is determined for each year of the rate plan. For example, in 2018 the rewards were split evenly between the DER utilization PIM and the average use PIMs. Of the 50% of the potential outcomes rewards assigned to the average use PIMs, 55% was assigned to the commercial average use PIM, 26% to the residential average use PIM, and 19% to the multifamily and public average use PIM. Support for these allocations was not provided.

A scorecard appraising a distributor's overall performance was envisioned in the REV proceeding. The scorecard is still under development. Nevertheless, a scorecard was developed for the company's AMI deployment which appraises Con Ed's success in achieving the benefits of AMI. In addition to reporting the number of AMI meters installed, the scorecard addresses the company's success at promoting customer awareness and engagement with AMI and the technologies and other benefits AMI enables as well as whether AMI helps Con Ed reduce the number of estimated bills, improve outage management, and improve operations due to conservation voltage optimization. These metrics are reported annually, with several having approved targets and several others having targets under development. Only one of these metrics, the effectiveness of Con Ed's AMI customer awareness strategy as measured by surveys of customers before and after AMI deployment, is linked to any financial rewards.

An area where Con Ed has been at the leading edge of targeted incentives is local non-wires alternatives ("NWAs"). The Company operates under 2 incentive mechanisms that encourage the development of NWAs: one for the Brooklyn/Queens Demand Management ("BQDM") program and one for all NWA programs implemented subsequent to the approval of the BQDM. We discuss each PIM in turn.

The BQDM program was one of the first instances where incentives targeted DSM and other DERs in a specific part of a utility's service territory.[48] Approved by the New York Public Service Commission in December 2014, this program relies on DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs. In the absence of the program, the upgrades needed by 2017 would have included a new area substation, a new switching station at an existing station, and associated subtransmission feeders. The total cost of these upgrades was estimated by Con Ed to be approximately $1 billion.

The BQDM program consists of approximately 50 MW of load reductions involving a variety of DERs. These load reductions will be drawn chiefly from customer-side projects but will also involve some utility projects. Together, these measures are expected to delay the need for the new substation for several years.[49]

The commission expressly designed the BQDM program to activate markets and foster third-party investment, goals consistent with its vision in the ongoing REV proceeding. For example, the program relies heavily on third-party market actors for the needed DER implementation. Con Ed is responsible for soliciting proposals for BQDM projects from third parties, selecting the portfolio of projects to implement, and contracting with these parties to implement them. The project solicitation and selection processes are overseen by an independent third party in order to ensure transparency and fairness. Projects considered include energy efficiency initiatives for residential, commercial, and public properties, procurement of peak load management resources, distributed generation, microgrids, and storage.

Successful implementation of the BQDM program defers or avoids traditional infrastructure investments, which would otherwise have been added to Con Ed's rate base. This creates a potential disincentive for the utility to implement the program. To avoid this, the commission adopted the following reward provisions:[50]

1. BQDM program costs were initially recovered via a surcharge. Following Con Ed's 2016 rate case, however, recovery via the surcharge ceased and remaining costs will be recovered through base rates but variances between amounts included in base rates and actuals will be deferred

[48] NY Public Service Commission (2014). Order Establishing Brooklyn/Queens Demand Management Program, New York Public Service Commission, Case 14-E-0302.

[49] Concurrently with the BQDM program, Con Ed is undertaking about 17 MW of traditional infrastructure investments.

[50] Con Ed had also proposed a third shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50% share of the annual net savings realized by customers. The commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.

for review in Con Ed's next rate filing. All BQDM project investments will be amortized over a 10-year period.

2. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred BQDM program costs. The commission felt that this measure should put BQDM projects on an equal footing with traditional capital projects from the utility's perspective.

3. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on BQDM program costs, conditional on Con Ed's performance on metrics tied to three outcomes.

    a. **Peak demand reductions from customer-side DER**. The MW reduction in peak-day load in the targeted area that is due to customer-side DER is calculated. Reductions equal to or less than 20 MW does not earn a reward. Beginning at a peak demand reduction of 21 MWs, the utility earns 1 basis point for each MW (up to a maximum of 45 basis points).

    b. **Diversity of customer-side DER providers.** A diversity index is calculated, based on the portfolios of customer-side DERs selected to achieve the needed peak load reductions in 2016, 2017, and 2018. Based on this index, the company is eligible to earn up to 25 additional basis points.

    c. **Reduction in $/MW costs.** The percentage reduction in the $/MW unit cost that the utility is able to achieve (relative to the avoided traditional infrastructure investments) is calculated. For every full 1% reduction, the utility earns 1 basis point (up to a maximum of 30 basis points).

Con Ed's subsequent NWA projects have had a different incentive mechanism. While the cost of an NWA project continues to be amortized over a 10-year period at the company's allowed rate of return with the costs tracked for recovery through a rider between rate cases, the ROE adders are not available. Instead, a PIM provides the company a share of the estimated net benefits of each NWA project that the company pursues. This reward is amortized over the effective life of the NWA project (e.g., the period of time in which an NWA project will result in the deferral or avoidance of the capex project) including carrying charges at Con Ed's approved weighted average cost of capital.

The method by which the financial reward is derived varies slightly based on the size of the project. If the project defers an infrastructure investment that would be rated at 69 kV or higher, the project is deemed to be large. These projects tend to defer investments at the area station level or higher, require longer lead times for execution (e.g., 3 years or longer), and defer more costs from traditional infrastructure investments. Projects that would defer infrastructure investments at less than 69 kV are deemed to be small, deferring fewer costs on a project by project basis, requiring less lead time, and have a simplified process for reward calculations.

The net benefits calculation requires the filing of a benefit cost analysis prior to project commencement. This includes a comparison of the present value of the costs and benefits of undertaking a traditional utility investment and the costs and benefits of DER alternatives that would be necessary to defer or avoid a traditional solution. The difference between these calculations is the net benefits of the NWA projects compared to the traditional investment. The composition of the benefit cost analysis and the calculation of net benefits varies between small and large projects, with small projects including fewer benefits for NWA projects. For large projects, the benefit cost analysis includes numerous avoided costs at the wholesale and distribution levels; reliability benefits; avoided impacts from emissions, land use, and water use; DER costs; program administration costs; lost utility revenues; and shareholder rewards. Small projects rely on a simplified benefit cost analysis which excludes non-energy benefits other than carbon (e.g., economic growth, health impacts of non-wires alternative projects) and any benefits associated with the deferral of the traditional project.

These net benefit calculations conducted prior to the deployment of the NWA are often referred to as “Initial Net Benefits”, and Con Ed receives 30% of initial net benefits as a reward for undertaking these projects. For large projects Con Ed collects the reward once 70% of the NWA deployment is operational and has been verified. For small projects the Initial Net Benefits are divided by the MW of avoided load required, which Con Ed collects as each MW of the NWA becomes operational and has been verified. If a small project involves less than 1 MW of avoided load, Con Ed must wait for the entire project to become operational and be verified. Recoveries of rewards will be halted without the need for refunds if the NWA is determined to be operationally or technically infeasible.

After the NWA is deployed, the Initial Net Benefits calculation is adjusted to reflect the actual non-wires alternative cost. This adjustment can be an increase in the share of Initial Net Benefits if the company is able to deliver the targeted savings at a lower cost than forecast or a decrease if costs were higher than expected. In some instances, a second adjustment to reflect changes in the MW of avoided load that is needed to defer the traditional investment may be needed. If the MW of avoided load required is reduced, the Initial Net Benefits and actual costs would be calculated on a per MW basis and reduced accordingly. If the MW of avoided load required is increased, the additional NWA procurement will not be eligible for any rewards beyond the 10-year amortization period at Con Ed’s approved rate of return. Additional NWA procurement would also not be factored into the comparison of actual and forecast costs.

In no event will Con Ed’s share of Initial Net Benefits be lower than the floor of $0 or higher than the cap of 50% of Initial Net Benefits. This reward is amortized over a 10-year period, accruing interest at the Con Ed’s approved weighted average cost of capital.

The existing “claw back” mechanism was adjusted to exclude the revenue requirement associated with any capital projects deferred due to NWAs in the capital true ups. Instead, the revenue requirement reduction will be used to offset the cost of the NWA project.

Central Hudson Gas & Electric

Central Hudson Gas & Electric ("Central Hudson") has a set of PIMs that are similar to Con Ed's. These PIMs were outlined in a settlement that resolved issues in the company's most recent rate case.[51] PIMs encourage focus on similar areas of capex containment and beneficial electrification and feature targets that are set for each year in advance.[52] Targets are set for minimum, target, and maximum levels of performance. These PIMs are asymmetric, providing rewards for good performance.

Central Hudson's conservation PIM contains a single metric of the overall MWh savings from DSM programs administered by the Company. Central Hudson also has a PIM that encourages the company to reduce customer average use. This PIM has separate metrics and targets for different customer classes. For residential customers, weather normalized MWh sales are adjusted for allocations of community distributed generation and increased sales from beneficial electrification technologies (e.g., heat pumps and electric vehicles).[53] This is then divided by the 12-month average number of residential customers. A second metric was developed for commercial customers with a similar design.

The Company also has PIMs for peak load management and DER utilization. The metric for peak load management is the sum of the weather-normalized demand on the Central Hudson system coincident with the NYISO Zone G-J Locality peak and the amount curtailed from contracted resources enrolled in the NYISO's Installed Capacity – Special Case Resource program at the coincident peak. The target appears to be based on recent historical peak demand. The rationale for the reward levels was not provided in the settlement.

The DER utilization PIM is designed to encourage Central Hudson to work with third parties to expand the use of DERs in its service territory. The metric for this PIM is the sum of the annualized production MWh from Community PV and of combined heat and power, fuel cells, battery storage charging and discharge. The annualized MWh calculations are based on assumptions on capacity factor for each type of production (Community PV, combined heat and power, and fuel cell) or the discharge rating of batteries and round-trip efficiency of batteries.

A third PIM incentivizes Central Hudson to increase residential customer participation in voluntary TOU rate programs. The metric is the percentage of Central Hudson's residential customers that sign up for TOU pricing programs.

Central Hudson also has a PIM for environmentally beneficial electrification. The metric for this PIM is the incremental lifetime tons of avoided carbon dioxide from environmentally beneficial

[51] NY Public Service Commission (2018). Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans. New York Public Service Commission, Case 17-E-0459.

[52] There are also PIMs in areas not tied to capex containment, such as encouraging environmentally beneficial electric use and the maintenance of reliability and customer service quality.

[53] Sales from beneficial electrification technologies were assumed to be 3.9 MWh from electric vehicles and 4.5 MWh from heat pumps.

electrification technologies. The current list of technologies is limited to electric vehicles and various types of heat pumps, though Central Hudson can propose other technologies as part of a future Carbon Reduction Implementation Plan.[54] Assumptions about the lifetime and annual avoided tons of carbon dioxide are required for these calculations. For example, each electric vehicle that is registered in Central Hudson's service territory is assumed to run for 10 years and prevent the emission of 3.8 short tons of carbon dioxide per year.

Central Hudson also has rewards to encourage the pursuit of successful NWA projects. Projects that were approved in the second half of 2018 are subject to the incentive package described below.[55] This package allows for the capitalization of project costs and rewards at the pre-tax rate of return with different amortization periods. Project costs have a 10-year amortization period that begins when project costs are realized, while rewards are amortized over the period for which the traditional investment is deferred. Rewards are calculated as a share of the estimated net benefits from a benefit cost analysis compared with a traditional investment option with a floor of $0 and a cap of 50% of initially-identified net benefits.

Projects are separated into small and large, with large projects having a more expansive benefit/ cost analysis. Rewards for large projects can be collected once 70% of the MW procured for NWA project have become operational and been verified through a measurement and verification procedure. Rewards for small projects can become collectible once each MW of DER becomes operational on a per MW basis. If a small project is reducing less than 1 MW of demand, the entire project must be operational prior to the recovery of rewards.

For large projects, the initial reward is set at 30% of the initial net benefits. After the project is deployed successfully, the reward will be adjusted to reflect the difference between the actual NWA project cost and the initial forecast, with the company at risk for 50% of the variance (positive or negative). The final reward is capped at 50% of initially-identified net benefits. The reward will not be adjusted if the company determines that additional MW are needed to defer the traditional investment. The reward will be adjusted if the company determines that fewer MW are needed to defer a traditional investment only if the need for reduced MW to achieve deferral is on a sustained downward trend over a three-year period and the Company needs only 70% or less of the initially forecast avoided MW to achieve the investment deferral. In that case, the reward calculations will be made on a per-MW basis, multiplied by the reduced amount of MWs ultimately required. If the project is not deemed to be feasible after approval, the company will cease collecting the rewards but is not required to refund rewards it had already collected. The reward calculation is similar for small projects.

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[54] There are two kinds of electric vehicles that count towards this metric: plug-in hybrid electric vehicles and battery electric vehicles. There are also two kinds of heat pumps that count for this metric: air source heat pumps and ground source heat pumps. The avoided carbon dioxide assumption does not vary between kinds of electric vehicles but does vary between kinds of heat pumps.

[55] Projects that were underway at the time of the company's most recent rate case (e.g., the first half of 2018) were grandfathered into the previous NWA incentive package.

The existing “claw back” mechanism was adjusted to exclude the revenue requirement associated with any capital projects deferred due to NWAs in the capital true ups. Instead, the revenue requirement reduction will be used to offset the cost of the NWA project.

Niagara Mohawk

Niagara Mohawk has a similar set of PIMs that were also outlined in a settlement that resolved the issues in the company’s most recent rate case. These PIMs encourage good performance in the areas of conservation, peak load management, and DER utilization.[56] There are also incentives for the company to undertake successful local NWA projects. These PIMs are all asymmetric and reward good performance. Targets and financial rewards for these PIMs, excepting the non-wires alternative PIMs, vary by year. We discuss each of these PIMs in turn.

Niagara Mohawk’s conservation PIM has four metrics: overall MWh savings from the Company’s DSM programs in excess of the company’s annual savings target, MWh savings from LED streetlight conversions, residential energy intensity, and commercial energy intensity.

The LED streetlights metric encourages Niagara Mohawk to convert streetlights to LED lighting. The company is rewarded for exceeding an MWh savings target. The energy intensity metrics measure weather normalized use per customer for each of the residential and commercial customer classes. These metrics are calculated by adjusting actual sales for weather and then subtracting the new sales from beneficial electrification (e.g., electric vehicles and heat pumps). This is then divided by the 12-month average number of customers.

The PIM for peak load management relies on a metric which is the sum of the weather normalized demands on the Niagara Mohawk system coincident with the NY Control Area peak and the amount curtailed from contracted resources enrolled in the NYISO’s Installed Capacity – Special Case Resource program at the NY Control Area peak. The rationale for the reward amounts was not provided in the settlement.

The DER utilization PIM is designed to encourage Niagara Mohawk to work with third parties to expand the use of DERs in its service territory. The metric for this PIM is the MWh of annualized Community and Rooftop Solar PV, combined heat and power and fuel cell production, and of battery storage charging and discharge.

Niagara Mohawk has a PIM for environmentally beneficial electrification. The metric for this PIM is the incremental lifetime metric tons of avoided carbon dioxide from environmentally beneficial electrification from incremental electric vehicle registrations and heat pump installations.[57] Incremental

[56] There are also PIMs in areas not tied to capex containment, such as encouraging environmentally beneficial electric use and the maintenance of reliability and customer service performance.

[57] There are two kinds of electric vehicles that count towards this metric: plug-in hybrid electric vehicles and battery electric vehicles. There are also two kinds of heat pumps that count for this metric: air source heat pumps and ground source heat pumps. The avoided carbon dioxide assumption does not vary between kinds of electric vehicles but does vary between kinds of heat pumps.

electric vehicles is defined as the number of electric vehicle registrations in excess of the expected amount. The expected number of electric vehicle registrations is calculated as 55.7% of the electric vehicle registrations for a peer group of zip codes that are similar to Niagara Mohawk's service territory based on the numbers of customers and income levels.[58] Assumptions about the lifetime and annual avoided metric tons of carbon dioxide are required for these calculations. For example, each incremental electric vehicle is assumed to run for 10 years and prevent the emission of 3.85 metric tons of carbon dioxide each year.

Niagara Mohawk also has an incentive package to encourage successful NWA projects. This package allows for capitalization of project costs and rewards at the pre-tax rate of return. The amortization periods differ for project costs and rewards as project costs are amortized over a 10-year amortization period that begins when project costs are realized, while rewards are amortized over the period in which the traditional investment is expected to be deferred. The rewards are a share of the estimated net benefits from a benefit/cost analysis compared with a traditional investment option with a floor of $0 and a cap of 50% of initially-identified net benefits.

Projects are separated into small and large, with large projects having a more expansive benefit cost analysis. For Niagara Mohawk, large projects defer traditional projects with capital cost in excess of $1 million. Rewards for large projects can be collected once 70% of the MW procured for the non-wires alternative project have become operational and been verified through a measurement and verification procedure. Rewards for small projects can become collectible once each MW of DER becomes operational on a per MW basis. If a small project is deferring less than 1 MW of demand, the entire project must be operational prior to the recovery of rewards.

For large projects, the initial reward is set at 30% of the initial net benefits. After the project is deployed successfully, the reward will be adjusted to reflect the difference between the actual NWA project cost and the initial forecast, with the company at risk for 50% of the variance (positive or negative). The final reward is capped at 50% of initially-identified net benefits. The reward will not be adjusted if the company determines that additional MW are needed to defer the traditional investment. The reward will be adjusted if the company determines that fewer MW are needed to defer a traditional investment only if the Company subsequently determines that it needs 70% or less of the initially forecast MW reduction and the need for reduced MW is on a sustained downward trend over a three-year period. In that case, the reward calculations will be made on a per-MW basis, multiplied by the reduced amount of MWs ultimately required. If the project is not deemed to be feasible after approval, the company will cease collecting the rewards but is not required to refund rewards it had already collected. The reward calculation is similar for small projects.

The existing "claw back" mechanism was adjusted to exclude the revenue requirement associated with any capital projects deferred due to NWAs in the capital true ups. Instead, the revenue requirement reduction will be used to offset the cost of the NWA project.

[58] This relationship was calculated based on data for Niagara Mohawk and the peer group from 2010-2017.

Rhode Island

The state of Rhode Island is currently reconsidering its approach to regulating its only major power distributor, Narragansett Electric, in the Power Sector Transformation regulatory initiative. Narragansett had recently operated under traditional cost of service regulation supplemented by expansive capital cost trackers with energy efficiency and renewable procurement PIMs. The state of Rhode Island issued a paper calling for a new approach to regulation featuring multiyear rate plans and additional PIMs.[59] One outcome of the Power Sector Transformation initiative was Narragansett Electric's proposed Power Sector Transformation plan.

A settlement resolving Narragansett Electric's most recent rate case outlined an MRP and several policy PIMs. Most of the PIMs detailed in this settlement were deferred for further review, were reduced to reporting requirements only, or were outright rejected by the Rhode Island Commission.[60] The parties agreed that stakeholders would collaborate in the development of metrics to describe and provide evidence of unquantified benefits resulting from the approval of a slimmed down Power Sector Transformation plan that may inform the development of future PIMs.

The one PIM that was approved in the final decision involves the company's efforts to reduce peak demand. The metric used is the MW of annual peak demand savings from eligible resources coincident with the peak of the New England Independent System Operator. Eligible resources that count towards performance on this metric include peak load management, incremental net-metered solar DG above the Company's forecasted levels, incremental installed energy storage capacity, and any additional actions the Company can identify to reduce peak demand such as NWA projects and partnerships with third-parties to provide peak demand reduction programs.[61] This last option includes NWA programs. Assumptions for each eligible resource were also outlined, including an assumption that each residential customer that participates in the Company's peak load management program will have a kW savings of 0.46 kW per installed thermostat.

Targets for this metric were established at three thresholds: minimum, target, and maximum, with separate rewards for each. These targets are for a total count of savings from eligible resources rather than targets for each type of eligible resource and vary by year. Rewards for meeting or exceeding the any of the targets increase each year. No penalties are applied if the company fails to meet the minimum target.

The Rhode Island Commission also approved a scorecard with metrics for incremental installed energy storage capacity, DG interconnection timeliness, the number of DG-friendly substation transformers installed (e.g., transformers that better address voltage concerns), and the number of

[59] Rhode Island Power Sector Transformation Phase One Report To Governor Gina Raimondo, November 2017.

[60] PIMs that were changed into metrics without financial incentives that do not encourage capex containment include metrics on electric vehicle deployment and the use of electric vehicle supply equipment.

[61] To avoid double counting, incentives for demand response were removed from the Company's energy efficiency PIM.

residential customers of nonregulated power suppliers that participate in the Company's peak load management programs.[62]

A PIM for variances between actual and targeted capex which is currently tracked outside of base rates was deferred to a separate docket.[63] This proposed PIM assumed that the revenue requirement from capex was 20% of capex and included a dead band of +/- $2.5 million in capex. Narragansett would absorb between 40 and 100% of overspending and be allowed to keep 50% of underspends beyond the dead band.

Rhode Island's statutes outline 2 PIMs to encourage Narragansett Electric to procure renewable energy and spur new renewable developments. Both PIMs take the form of management fees, which provide Narragansett Electric with a payment based on the total spending on the programs. These PIMs are asymmetric, such that Narragansett Electric cannot qualify for a penalty.

The first serves to reward Narragansett Electric for entering into contracts resulting from competitive solicitations for at least 90 MW of long-term (e.g., at least 10 years) power procurements from newly constructed renewable resources. This PIM provides Narragansett Electric with 2.75% of the average annual payments made to renewable generators for long term renewable procurement.[64]

The second PIM outlined in the Rhode Island statutes encourages Narragansett Electric to connect distributed generation. Narragansett Electric receives 1.75% of annual payments and some net metering credits. This PIM is contingent on Narragansett Electric meeting targets for the MW of DG connected under this program and the timeliness and prudence with which Narragansett Electric provides DG interconnections.

California

The California Public Utilities Commission ("CPUC") regulates the generation, intrastate transmission, and distribution services of three major electric utilities and several smaller electric utilities. California utilities have typically operated in recent years under MRPs with energy efficiency PIMs.[65]

The CPUC has developed a statewide pilot incentive program for DERs such as distributed generation and storage.[66] The reward takes the form of a management fee that would offer utilities 4

[62] This is measured by the average number of business days between receipt of an application for interconnection and the issuance of an executable Interconnection Service Agreement compared to the timeframe outlined in the company's tariff.

[63] This is an interesting middle course between PIM and incentivized cost tracker. We describe this as a PIM as it does not directly influence the amounts flowing through the tracker, instead serving as a separate mechanism entirely.

[64] A similar provision was enacted in Massachusetts, where distributors are eligible for a 2.75% management fee for long-term procurements of renewable energy.

[65] At least one utility, San Diego Gas & Electric, has approved PIMs for customer service and reliability.

[66] The California PUC uses the term "regulatory incentive mechanism pilot" for this specific incentive program.

percent of annual payments made to third-party DER providers pretax as an reward to use DERs to cost-effectively displace or defer the need for capex for traditional distribution system investments that were previously planned and authorized.[67] Utilities are required to pursue at least one project and have the option to pursue three more.

The CPUC has also authorized the utilities to keep any savings until the next general rate case from capex underspends, relative to amounts previously approved, which are attributable to DERs. Estimated costs of the DERs and administration of the solicitation are deferred with interest up to a preapproved cap until rates are reset in the next rate case. Administrative costs above the cap will be reviewed for reasonableness in the next rate case.

In their procurement decisions, utilities are required to consider the net market value of potential DER pilot projects. The net market value calculation includes a broad range of factors, including capacity, energy, ancillary grid services, costs of grid integration, deferred distribution and transmission system costs, and the cost of the DER procurement contract. During the pilot, each of the three major electric utilities are allowed to use different methods for ensuring that DERs subject to the incentive mechanism are incremental to the utility's existing plans and efforts as governed by other Commission proceedings, in order to test the performance of each method.

San Diego Gas & Electric was the first distributor to file the results of their procurement efforts with the CPUC. The company's solicitation did not receive any cost-effective bids.

Australia

The Australian Energy Regulator ("AER") acts as the economic regulator for Australian wires companies that serve the National Energy Market, defined as the entirety of Australia except the state of Western Australia. There are 14 jurisdictional power distributors. Australia recently reconsidered its approach to regulating power distributors in the Better Regulation regulatory initiative. This initiative served to refine the regulator's approach to cost forecast appraisals and improved the balance of incentives between capex and opex solutions. Australian distributors have typically operated in recent years under MRPs with reliability PIMs. These distributors have generally experienced flattening, if not declining, peak demand with limited network constraints from peak demand due in part to growth in distributed generation. Distributed generation has contributed to the sluggish trend in peak demand but may potentially lead to voltage regulation issues on the network. Peak demand itself has been difficult to forecast in recent years.

Demand management projects potentially address several potential network constraints resulting from growth in peak demand, aging assets and the risk of equipment failures, power quality issues, the need to manage power flows and system security issues. Projects may combine many kinds of DERs including distributed generation and storage, demand-side management, and peak load management. Costs of demand management projects that are innovative may be funded by a

[67] The California PUC expressed its support for the utilities to undertake customer awareness effort to inform customers that DER providers may contact them.

supplemental revenue allowance.[68] Other demand management project costs are funded, if successful, by allowing the distributor to receive the benefit of underspending their capex forecast.

The AER outlined a specific process by which demand management rewards may be earned. First, the distributor must identify a network constraint that can be potentially addressed by a demand management project. Distributors must solicit competitive bids for the project. The selected demand management project must maximize the net economic benefit relative to a base case. For projects where the identified need is to ensure the company meets its reliability standards, the option with the next highest net benefit is the base case. For all other projects the base case is the net benefit of distributor inaction. The distributor then must demonstrate a commitment to the project. Project commitment is defined as entering into a contract or, for projects undertaken by the distributor itself, a declaration that the company has approved its own demand management proposal supported by evidence showing that the proposed costs are reasonable.

The distributor then calculates the reward for an eligible project equal to 50% of the present value of the forecasted efficient cost of the project. Costs of network investments to ensure successful delivery of the project are excluded from the reward. This reward is capped at the lesser of the present value of the cost of the project less any government subsidies provided to the distributor for the project (excluding subsidies for network investments related to the demand management project) and the expected present value of the project's net economic benefit to all those who produce, consume, and transport energy in the affected market. The demand management incentive scheme is designed to only provide positive rewards.

The total reward for all projects is capped each year at 1% of a distributor's annual revenue requirement. If a distributor terminates a demand management project early, it may be required to return rewards it received for the period after the termination.

After a project is approved, the distributor presents annual reports on the effectiveness of the project including the kVa of demand provided in the reporting year controlled by the distributor for each committed project, its estimate of benefits from demand management for the reporting year, and the total financial reward that it claims for that year. Distributors are also required to report on the eligible projects that it has not yet committed to that would qualify for the reward. This reporting includes the expected costs and benefits that each project would accrue to customers, a description of the bids the distributor received for each project, the expected costs of the demand management project, the kVa of network demand project would be able to call upon, and if the distributor expects to obtain third party services for the demand management project.[69]

[68] To be an innovative project, the cost must be based on a new concept, involve new techniques or technologies in the relevant market, or be focused on a different segment of customers if the technique isn't new to that market.

[69] The report also requires the potential demand management provider to be named.

The AER reviews the annual report and proposed financial reward. Any approved financial reward is applied with a 2-year lag. This mechanism is expected to be included in the next generation of multiyear rate plans for all AER-regulated power distributors.

PIMs for Total Cost, Capital Cost, and Capex

Regulators in several countries use sophisticated benchmarking methods to appraise total cost, totex, or capex. Econometric benchmarking of total power distribution cost by the Ontario Energy Board was noted above. The Australian Energy Regulator has developed models to benchmark augmentation (growth related) and replacement capex and uses simpler methods to benchmark other kinds of capex.

A.4 The RIIO Approach to PBR

The structure and regulation of electric utilities in Britain differ in important respects from those of most American utilities. Until 1990, British electric utilities were not investor owned.[70] In the intervening years these utilities have been privatized and restructured into separate generation, transmission, distribution, and retail operations. Power distributors do not directly bill end users, instead billing the retailer who then bills end users. This arrangement reduces the ability of distributors to develop DSM programs that encourage more efficient use of the system. Currently, there are 14 power distributors in Britain, as well as 8 gas distributors, 3 electric transmitters, and one gas transmitter. All of these utilities are regulated by Ofgem.

Since privatization British regulation has featured MRPs called price controls. Revenue escalation has been based on multiyear cost forecasts with updates for inflation. Ofgem has refined various features of the MRPs over the years in its periodic price control reviews. These refinements have included the addition of several performance metrics and PIMs. Ofgem undertook a particularly extensive reconsideration of its regulation beginning in 2008. This review led to the adoption of the current RIIO system. RIIO stands for Revenues = Incentives + Innovation + Outputs.

The RIIO framework should be viewed as an evolution of the previous system wherein many of the previous features were kept, albeit with some changes. The attrition relief mechanisms in the MRPs continue to be revenue caps based on cost forecasts approved by Ofgem and indexed to inflation. The terms of the MRPs were lengthened from 5 years to 8.[71] The use of performance metrics was maintained, with updated targets and some new metrics and PIMs. Revenue decoupling was also continued through the "correction factor."

The "outputs" term of the RIIO acronym refers to a focus on results in a range of performance areas. An elaborate performance metric system is used to monitor outputs and measure performance.

[70] British gas utilities were privatized in 1986.

[71] Ofgem recently proposed to reduce the MRP term to 5 years in the next generation MRPs.

Several metrics are used in PIMs. Some outputs are addressed by other ratemaking treatments such as cost trackers, reputational incentives, and discretionary incentives (discussed further below).

Outputs are monitored in six non-cost performance areas: safety, environmental impact, customer satisfaction, social obligations, connections, and reliability. Ofgem has divided these outputs into "primary" and "secondary" outputs. Primary outputs have a direct impact on customers. Secondary outputs shed light on how primary outputs are achieved. Companies can propose additional metrics in their business plans. Numerous metrics are used to measure outputs, but some outputs are not quantified.

While non-cost performance receives considerable attention in RIIO, cost is also an extremely important consideration. Ratemaking tools used to address cost include statistical benchmarking and a complicated PIM called the information quality incentive ("IQI").

The IQI encourages utilities to provide honest forecasts of their total expenditures ("totex") and permits utilities to share in the benefits of better cost performance. This mechanism sets the revenue requirement, determines the sharing of variances between actual and forecasted costs (the totex efficiency incentive), and provides an immediate reward or penalty based on the reasonableness of the company's forecast (the ex-ante reward/penalty).

The IQI functions as an incentive-compatible menu in the spirit of work by Nobel prize-winning economist Jean Tirole.[72] In such a menu, a utility can choose from amongst several combinations of ratemaking provisions, such as allowed revenue and earnings sharing factors. The menu is designed so that the utility, by its choice, reveals the cost it can achieve, thereby reducing information asymmetry. For example, a utility that requests a lower level of allowed revenue that more closely matches the regulator's assessment of efficient costs would be rewarded with an ex-ante reward and a greater portion of any savings in total expenditures relative to allowed expenditures.

RIIO's performance metric system includes reporting requirements, PIMs, and discretionary financial incentives. We discuss each of these in turn.

Distributors are required to annually report on numerous metrics. Ofgem will then review these data and issue its own report summarizing each distributor's performance. Ofgem's reports feature scorecards with "traffic lighting," where the color red is used to indicate poor performance, green is used to indicate good performance, and yellow indicates performance in between. This traffic lighting facilitates a quick visual assessment of distributors' performances.

Table A1 provides an overview of PIMs for power distributors under RIIO.[73] As can be seen, the performance areas addressed are largely similar to those addressed by PIMs in North American multiyear rate plans. The notable exception is the IQI mechanism.

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[72] See Laffont, J. and Tirole, J. (1993).

[73] Most of the PIMs in RIIO were included in British MRPs prior to RIIO.

Table A1

Summary of PIMs in RIIO

Performance Areas	Metrics	PIMs
Safety	Asset health, criticality, and risk indexes	Penalty or reward of 2.5% of avoided/incurred costs in future MRP
Customer Satisfaction	Customer satisfaction survey	Reward or penalty with collar of +/-57.3 basis points of ROE
	Complaints	Penalty only: floor of 28.7 basis points of ROE
Connections	Guaranteed standards of performance	Direct payment to customer of a fixed amount per offense
	Time to quote	Reward only: ceiling of 23 basis points of ROE
	Time to connect	
Reliability	Customer interruptions	Reward or penalty with symmetric collar of 250 basis points of ROE per year
	Customer minutes lost	
	Guaranteed standards of performance	Direct payment to customer of a fixed amount per offense
Cost[74]	Totex efficiency incentive	Rewards/penalties with sharing percentage based on Ofgem's final cost assessment
	Ex-ante reward/penalty	Annual reward/penalty based on Ofgem's assessment of cost forecast

[74] Cost is not identified as an output by Ofgem but is nonetheless the subject of a PIM.

Several of these PIMs merit further discussion. The risk index is a composite measure of asset health and criticality indexes and reflects the risk of asset failures for a distributor. The asset health index measures the likelihood of an asset failure while the criticality index measures the impact of a potential asset failure.

The customer satisfaction PIMs use the results of a customer satisfaction survey and a complaints metric. The customer satisfaction survey factors in the number of unsuccessful calls (defined as calls terminated by the distributor or calls abandoned by the customer), as well as the score a customer gives regarding the quality of service received. The survey has a component for each type of customer call: connections, interruptions, and general inquiries. The complaints metric is a weighted average of the percentage of total complaints unresolved after one day, the percentage unresolved after 31 days, the percentage that are repeated, and the percentage of Energy Ombudsman decisions that go against the distributor.

The reliability PIMs include an Interruptions Incentive Scheme that involves outage frequency and duration metrics. There are additionally guaranteed standards of performance for service to individual customers. One example is a requirement to restore service within 12 hours in normal weather conditions. The distributor must make pre-determined payments directly to the customer each time a minimum performance standard is not met.

In addition to PIMs, RIIO also features several “discretionary financial incentives.” These incentives are not linked mechanistically to metrics and targets and are therefore more subject to Ofgem’s discretion. Nevertheless, these mechanisms have many features in common with PIMs. For instance, they encourage distributors to focus on maintaining or improving their performance in specific areas and they may have a financial impact depending on the distributor’s performance.

Table A2 provides an overview of the five discretionary financial incentives for power distributors under RIIO. The losses discretionary incentive addresses distributor development and implementation of innovative and efficient strategies for reducing network losses. The stakeholder engagement incentive encourages distributors to engage with customers and incorporate their input in its decisions and to identify vulnerable customers and take efforts to ensure that their energy and non-energy needs are met. The incentive on connections engagement assesses a distributor’s effort in formulating and pursuing a strategy for providing and improving connection services to large customers, as well as a distributor’s use of information learned from these customers to improve connection services. The load index measures substation loading on a distributor’s primary network.

Tables A1 and A2 show that the financial incentives associated with the various outputs in RIIO are heterogeneous. Many are or can be measured in terms of basis points of ROE. However, the losses incentive mechanism is a fixed dollar amount spread across the distributors for the entire 1st generation of RIIO. Some information, like the expected number of guarantees made to customers that are broken and the specific cost levels at risk for potential rewards and penalties are also not readily available. It is therefore difficult to determine the relative weights assigned to these mechanisms or their financial impact. Nevertheless, it is possible to identify the maximum potential impacts of those mechanisms that are linked to the ROE. These are presented in Table A3.

Table A2

Summary of Discretionary Financial Incentives in RIIO

Performance Area	Measure	Possible Outcome
Environmental Impact	Losses discretionary incentive	£32 million reward that can be distributed between the 14 distributors over 8 years
Social Obligations	Stakeholder engagement incentive	Rewards only: ceiling of 28.7 basis points of ROE
Connections	Incentive on connections engagement	Penalties only: floor of 52 basis points of ROE
Reliability	Load index	Potential penalty in the next price control

Table A3

Estimate of the Maximum ROE Impact from PIMs and Discretionary Financial Incentives

Metric	**Maximum Reward**	**Maximum Penalty**
Customer satisfaction survey	57.3 basis points of ROE	57.3 basis points of ROE
Complaints	None	28.7 basis points of ROE
Stakeholder Engagement Incentive	28.7 basis points of ROE	None
Time to quote & time to connect	23 basis points of ROE	None
Incentive on Connections Engagement	None	52 basis points of ROE
Interruptions Incentive Scheme	250 basis points of ROE	250 basis points of ROE

It can be seen that of these incentives the Interruptions Incentive Scheme has by far the largest potential impact on the allowed ROE amongst these mechanisms. A utility that performed perfectly on all of these metrics would see their allowed ROE rise by more than 350 basis points, while a utility that had the worst possible performances would see their allowed ROE fall by nearly 400 basis points. More than 70% of the upside risk and 60% of the downside risk of these mechanisms result from the Interruptions Incentive Scheme. This is not surprising since the incentive for cost containment can be quite strong in MRPs with eight-year terms, and this jeopardizes reliability.

Ofgem has estimated the possible range of distributor ROEs under RIIO due to financial incentives. It included incentives that are not formally tied to the ROE. These estimates are depicted in Figure A1 for ten distributors. It can be seen from this figure that adjustments can potentially raise or lower ROEs by more than 400 basis points.

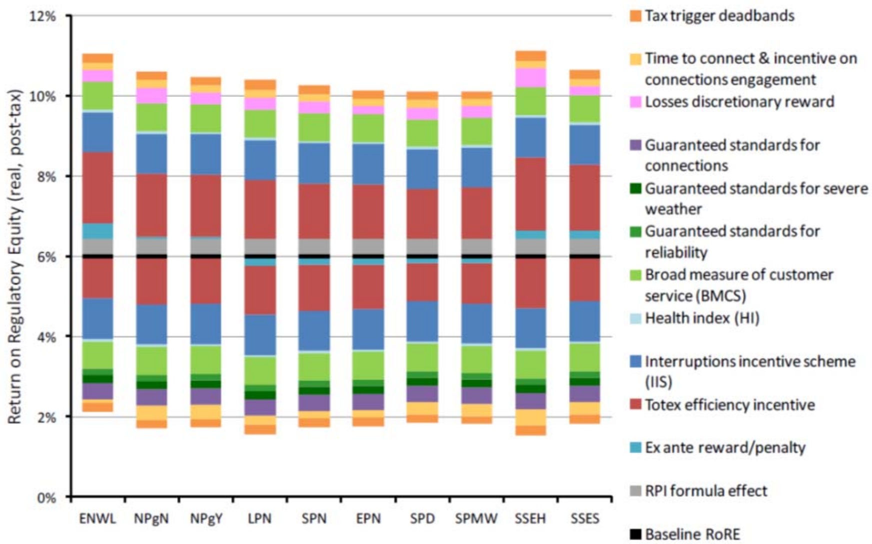
Reviewing the possible overall impact of the incentive mechanisms on a distributors' ROE allows us to draw some further conclusions about the relative importance of these mechanisms.

- The two financial incentive components of the IQI (e.g., the ex-ante reward/penalty and the totex efficiency incentive) are generally expected to have the largest financial impact.
- The reliability PIMs (e.g., the Interruptions Incentive Scheme, the guaranteed standards for reliability and severe weather, and the health index) are also expected to have a relatively large impact on a distributor's ROE.
- The large potential impacts of these incentive mechanisms are thus due primarily to the fact that RIIO involves multiyear rate plans with unusually long terms and rate escalators based on cost forecasts.
- Many of the mechanisms that are not commonly used in the U.S. (e.g., the risk index, time to connect, and incentives on connections engagement) are expected to have a very small impact.
- The discretionary financial incentives are expected to have a smaller impact on distributor ROEs than the PIMs.

The environmental metrics in RIIO are not linked to financial incentives. The business carbon footprint reports on the various activities of the distributors that result in greater carbon emissions. The reporting requirement for these outputs will result in a "league table" that allows easy comparisons of performances between distributors, thus resulting in a reputational incentive for distributors to improve their performance.

Figure A1

Ofgem's Estimate of the Potential ROE Impact of Financial Incentive Mechanisms



A.5 Glossary of Terms

Attrition Relief Mechanism ("ARM"): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital.[75]

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

[75] Base rates sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Earnings Sharing Mechanism ("ESM"): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism: A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Lost Revenue Adjustment Mechanism ("LRAM"): A ratemaking mechanism that compensates utilities for base rate revenue lost from specific causes such as demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to discourage predation and cross-subsidization.

Multiyear Rate Plan ("MRP"): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

Performance-Based Regulation ("PBR"): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism ("PIM"): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce or eliminate the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

Scorecard: A summary of activities that often includes performance appraisals.

Statistical Benchmarking: The use of statistics on the operations of utilities to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

Z Factor: A term in a rate or revenue escalation formula that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are difficult to foresee and beyond the utility's control.

A.6 Credentials

Mark Newton Lowry is President of Pacific Economics Group Research LLC, a consulting firm that works primarily in the field of energy utility regulation and performance measurement. He has more than thirty years of experience as an industry economist and is internationally recognized for his work. Dr. Lowry has testified dozens of times on utility performance and PBR. He is also an expert on miscellaneous other forms of alternative regulation. His diverse clients have included regulatory commissions, government agencies, and consumer and environmental groups as well as utilities.

Dr. Lowry has for many years advised the Edison Electric Institute ("EEI") on PBR and other forms of Altreg, preparing several EEI white papers and surveys. He recently co-authored two white papers on PBR for Lawrence Berkeley National Laboratory.

Before joining PEG, Dr. Lowry was a Vice President of Christensen Associates in Madison and an Assistant Professor teaching energy economics at the main campus of the Pennsylvania State University. His resume includes numerous professional publications and speaking engagements. He has chaired several conferences on Altreg and utility performance measurement. A Cleveland area native, he attended Princeton University and holds a Ph.D. in applied economics from the University of Wisconsin – Madison. His offices are on Capital Square in Madison, WI.

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