Empirical Research in Support of Incentive Rate-Setting: 2012 Update

Report to the Ontario Energy Board

September 2013

Pacific Economics Group Research, LLC

The views expressed in this report are those of Dr. Lawrence Kaufmann, and do not necessarily represent the views of, and should not be attributed to, the Ontario Energy Board, any individual Board Member, or Ontario Energy Board staff.

Empirical Research in Support of Incentive Rate-Setting: 2012 Update

Report to the Ontario Energy Board

September 2013

Lawrence Kaufmann, Ph.D.
Senior Advisor

Dave Hovde, M.A.
Vice President

John Kalfayan, M.A.
Senior Economist

PACIFIC ECONOMICS GROUP RESEARCH, LLC
22 East Mifflin, Suite 302
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

TABLE OF CONTENTS

1. Introduction and Summary

1.1 Introduction

As part of our work advising staff on empirical research in support of incentive rate setting for electricity distributors, Pacific Economics Group Research (PEG) was asked to update our estimated industry total factor productivity (TFP) trend and econometric cost benchmarking model to include 2012 data. The TFP trend was to be computed for the 2002-2012 sample period for the industry aggregate that excluded Hydro One and Toronto Hydro. The econometric cost benchmarking model was to be estimated for the 2002-2012 sample period. The results of this benchmarking model would be used to evaluate each distributor's cost performance (including Hydro One and Toronto Hydro) and to set distributor-specific stretch factors for the Board's 4th Generation Incentive Rate-setting method.

The methods PEG uses to estimate updated TFP trends and benchmarking cost models are identical to those discussed in our May 31, 2013 report, with five exceptions.

First, at the Board's direction, PEG eliminated smart meter capital expenditures and incremental OM&A associated with smart meters from our TFP analysis. This was done to ensure that the industry's estimated "long-run" TFP trend was not distorted by the one-time costs associated with the smart meter program. The Ontario electricity distribution industry is not expected to experience a discrete, industry-wide capital investment of a similar magnitude over the term of 4th Gen IR, and including these smart meter costs in the estimated TFP trend could provide a misleading indication of the industry's TFP gains going forward.

Second, the coefficients used to establish cost elasticity-based weights for the output quantity and TFP indexes are derived from an econometric cost model where the dependent variable is the cost measure used in our TFP analysis. Recall from the May 2013 report that this cost measure differs from the costs used to benchmark distributors' cost performance.[1] For simplicity, PEG's May 2013 report used the same econometric model to benchmark distributors'

[1] In our previous work, the TFP-based cost measure differed from the benchmarking cost measure in three ways: 1) it included the costs of distributors' HV assets; 2) it excluded the LV charges paid by embedded distributors to host distributors; and 3) it excluded contributions in aid of construction (CIAC) from the capital measure. In the 2012 update, the cost measures also differ with respect to smart meter capital and OM&A expenditures, which are in the benchmarking cost measure but not the TFP cost measure.

costs and to derive cost-elasticity based weights, even though it is more accurate for cost elasticities used in TFP analysis to be derived from a cost model that uses the same cost measure that is used in the TFP analysis. The latter approach is unambiguously superior because it uses internally consistent cost measures in the TFP analysis and the econometric estimates used directly in that TFP analysis, and we have adopted it for the 2012 update.

Third, the Board asked PEG to test the sensitivity of long-run TFP growth to Province-wide conservation programs. We were provided data on net energy savings (in GWh) reported by OPA on these programs for each year between 2006 and 2011. Since PEG did not have 2012 data on these energy savings, we assumed they were unchanged from 2011. We also multiplied the OPA net energy savings in each year by 0.6, since Hydro One and Toronto Hydro together account for about 40% of energy deliveries in the Province but neither company is included in the sample PEG uses to measure the industry's output quantity or TFP growth.

Fourth, PEG was asked to consider whether variables presented in econometric work by other stakeholders are statistically significant. The only such variable that PEG had not previously investigated was the wind variable constructed by Power System Engineering. PEG therefore investigated whether this wind variable was a statistically significant cost driver in our econometric analysis. In the regression on the TFP cost specification used to determine output weights, the wind variable was not statistically significant at the 5% level. In the benchmarking regression, however, the wind variable was statistically significant. Given these mixed econometric results, plus the facts that PEG did not have 2012 data on this variable, the wind data are not collected by the Board and had not been vetted during the Working Group process, and concerns necessarily arise about how "wind" measures are mapped to distributors' service territories, PEG chose not to include the wind variable in its 2012 econometric research.

Fifth, PEG's 2012 update for the benchmarking analysis did not include updated measures of the LV charges paid by embedded distributors to host distributors. 2012 data on these charges were not available at the time this update was prepared. PEG therefore assumed that each distributor's 2012 value for these LV charges was equal to its 2011 value.

1.2 TFP and Input Price Results

Our 2012 econometric analysis of the TFP-based cost specification (Table 1) finds that customer numbers, system capacity peak demand, and retail kWh deliveries are statistically significant cost drivers. The estimates of the cost elasticities for these outputs are 0.408, 0.194, and 0.071, respectively. Accordingly, the cost-elasticity based weights applied to customer numbers, system capacity peak demand, and retail kWh deliveries when constructing the industry output quantity index are 0.606, 0.289 and 0.106, respectively[2].

PEG estimates that the industry's output quantity grew by 0.99% in 2012 from the previous year (Table 2). This is the most rapid change in output since the 2008 recession, although output growth was still below its average annual change over the 2002-2007 period. For the entire 2002-2012 period, output quantity grew at an average annual rate of 1.30%.

As part of our work to estimate input quantity growth, PEG updated input prices for 2012. The capital service price (Table 3) declined by 5.2% in 2012 from the previous year. This decline reflects the decline in interest rates experienced in the market which is reflected in the Board's approved cost of capital parameters. The regulatory weighted average cost of capital was estimated to be 7.08% in 2011 and 6.23% in 2012. The electric utility construction price index grew by only a modest 0.9%. On average, the capital service price increased at an average rate of 0.38% over the 2002-2012 period.

For OM&A input prices (Table 4), average weekly earnings for all workers in Ontario grew by 1.47% in 2012, which was nearly identical to inflation in the same index in 2011. Canada's GDP-IPI for final domestic demand grew by 1.78% in 2012. Inflation in overall OM&A input prices was 1.57% in 2012. OM&A input price inflation over the 2002-2012 period averaged 2.29% per annum.

Overall input prices (Table 5) declined by 2.62% in 2012. This decline was driven entirely by the 2012 decline in capital service prices. Overall input price inflation for 2002-2012 averaged 1.11% per annum.

[2] The weights on the outputs must sum to one, and the weight on each output is equal to its estimated cost elasticity divided by the sum of the cost elasticities i.e. divided by (0.408+0.194+0.071).

Table 1

Econometric Coefficients Used to Determine Output Weights

VARIABLE KEY

Input Price:	WK =	Capital Price Index
Outputs:	N =	Number of Customers
	C =	System Capacity Peak Demand
	D =	Retail Deliveries
Other Business Conditions:	A =	2012 Service Territory
	U =	Percent Lines Underground
	L =	Average Line Length (km)
	NG =	% of 2012 Customers added in the last 10 years
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.5978	90.0060
N*	0.4077	8.8770
C*	0.1942	4.1640
D*	0.0712	2.4960
WKxWK*	0.3075	11.2480
NxN*	-1.2366	-6.3740
CxC	-0.2488	-1.2890
DxD*	0.1596	2.0540
WKxN*	0.0299	1.9900
WKxC*	0.0297	2.1890
WKxD	0.0091	1.5720
NxC*	0.7869	4.6440
NxD*	0.1830	1.9880
CxD*	-0.3186	-3.3980
A	0.0063	0.3890
U	0.0206	1.3190
L*	0.3090	8.5940
NG	0.0079	0.6440
Trend*	0.0081	5.8210
Constant*	12.219	489.950
System Rbar-Squared	0.980	
Sample Period	2002-2012	
Number of Observations	780	

***Variable is significant at 95% confidence level**

Table 2

Output Quantity Trends for Ontario Power Distributors, 2002-2012

	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
Year	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Index**	**Growth**
2002	2,528,664		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.43%	15,124,270	1.13%	67,480,321,397	2.94%	102.13	2.11%
2004	2,647,118	2.15%	15,282,376	1.04%	68,588,997,365	1.63%	103.96	1.77%
2005	2,703,821	2.12%	15,710,004	2.76%	72,989,180,570	6.22%	106.85	2.74%
2006	2,748,114	1.62%	16,004,095	1.85%	71,323,881,577	-2.31%	108.22	1.28%
2007	2,781,589	1.21%	16,030,411	0.16%	75,581,326,413	5.80%	109.74	1.39%
2008	2,823,654	1.50%	16,040,362	0.06%	74,626,460,193	-1.27%	110.61	0.79%
2009	2,864,567	1.44%	16,095,983	0.35%	71,454,871,565	-4.34%	111.18	0.51%
2010	2,885,251	0.72%	16,172,034	0.47%	71,603,206,532	0.21%	111.84	0.59%
2011	2,919,186	1.17%	16,287,524	0.71%	71,223,956,582	-0.53%	112.80	0.86%
2012	2,954,040	1.19%	16,391,549	0.64%	71,808,750,725	0.82%	113.92	0.99%
Average Annual Growth Rate 2002-2012		**1.55%**		**0.92%**		**0.92%**		**1.30%**

Table 3

Calculation of Capital Service Price Index

Year	EUCPI	Annual Growth	WACC*	Annual Growth	Depreciation Rate	Capital Price Index	Capital Price Inflation	Three Year Moving Average
2002	130.5		8.30%		4.59%	16.74		
2003	130.6	0.1%	8.30%	0.00%	4.59%	16.82	0.5%	
2004	131.1	0.4%	8.30%	0.00%	4.59%	16.85	0.2%	
2005	133.6	1.9%	8.30%	0.00%	4.59%	17.01	0.9%	0.5%
2006	142.4	6.4%	7.74%	-6.88%	4.59%	16.88	-0.7%	0.1%
2007	148.8	4.4%	7.35%	-5.22%	4.59%	17.30	2.4%	0.9%
2008	150.3	1.0%	7.27%	-1.11%	4.59%	17.72	2.4%	1.4%
2009	151.1	0.5%	7.32%	0.63%	4.59%	17.93	1.2%	2.0%
2010	155.1	2.6%	7.40%	1.14%	4.59%	18.30	2.0%	1.9%
2011	160.1	3.2%	7.08%	-4.46%	4.59%	18.32	0.1%	1.1%
2012	161.6	0.9%	6.23%	-12.69%	4.59%	17.40	-5.2%	-1.0%
Average		**2.14%**		**-2.86%**			**0.38%**	**0.86%**
Standard Deviation		**2.03%**		**4.43%**			**2.22%**	**0.99%**
Standard Deviation/ Average		**95.0%**		**-155.0%**			**578.1%**	**114.7%**

* The WACC used in these calculations is the average of the approved cost of capital for each month of the calendar year.

Table 4

OM&A Input Price Inflation

	AWE- All Employees			GDPIPI			OM&A Price Index		
Year	Ontario	Annual Growth	Three Year Moving Average	Canada	Annual Growth	Three Year Moving Average	Level	Annual Growth	Three Year Moving Average
2002	710.73			90.23			100.00		
2003	728.23	2.43%		91.70	1.62%		102.21	2.19%	
2004	748.78	2.78%		93.38	1.81%		104.79	2.49%	
2005	776.19	3.60%	2.94%	95.40	2.15%	1.86%	108.16	3.16%	2.61%
2006	788.62	1.59%	2.66%	97.68	2.36%	2.10%	110.14	1.82%	2.49%
2007	818.93	3.77%	2.99%	99.98	2.33%	2.28%	113.88	3.34%	2.77%
2008	838.14	2.32%	2.56%	102.48	2.47%	2.38%	116.60	2.36%	2.51%
2009	849.15	1.31%	2.47%	103.75	1.24%	2.01%	118.11	1.28%	2.33%
2010	882.21	3.82%	2.48%	104.80	1.01%	1.57%	121.68	2.98%	2.21%
2011	894.71	1.41%	2.18%	107.23	2.29%	1.51%	123.73	1.67%	1.98%
2012	908.00	1.47%	2.23%	109.15	1.78%	1.69%	125.68	1.57%	2.07%
Average		**2.45%**	**2.56%**		**1.90%**	**1.93%**		**2.29%**	**2.37%**
Standard Deviation		**1.01%**	**0.29%**		**0.50%**	**0.32%**		**0.71%**	**0.27%**
Standard Deviation/Average		**41.17%**	**11.43%**		**26.34%**	**16.77%**		**31.01%**	**11.56%**

Table 5

Input Price Inflation

	OM&A Input Price						Capital Service Price			Input Price Inflation		
Year	GDPIPI-Canada	Annual Growth	Weight	AWE- All Employees-Ontario	Annual Growth	Weight	Index	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2002	90.23			710.73			16.74			100.00		
2003	91.70	1.62%	11.4%	728.23	2.43%	26.7%	16.82	0.47%	61.9%	101.13	1.13%	
2004	93.38	1.81%	11.4%	748.78	2.78%	26.7%	16.85	0.19%	61.9%	102.21	1.06%	
2005	95.40	2.15%	11.4%	776.19	3.60%	26.7%	17.01	0.92%	61.9%	104.04	1.77%	1.32%
2006	97.68	2.36%	11.4%	788.62	1.59%	26.7%	16.88	-0.74%	61.9%	104.29	0.23%	1.02%
2007	99.98	2.33%	11.4%	818.93	3.77%	26.7%	17.30	2.42%	61.9%	107.22	2.77%	1.59%
2008	102.48	2.47%	11.4%	838.14	2.32%	26.7%	17.72	2.39%	61.9%	109.80	2.38%	1.80%
2009	103.75	1.24%	11.4%	849.15	1.31%	26.7%	17.93	1.21%	61.9%	111.17	1.24%	2.13%
2010	104.80	1.01%	11.4%	882.21	3.82%	26.7%	18.30	2.04%	61.9%	113.86	2.39%	2.00%
2011	107.23	2.29%	11.4%	894.71	1.41%	26.7%	18.32	0.13%	61.9%	114.69	0.72%	1.45%
2012	109.15	1.78%	11.4%	908.00	1.47%	26.7%	17.40	-5.19%	61.9%	111.72	-2.62%	0.17%
Average		**1.90%**			**2.45%**			**0.38%**			**1.11%**	**1.44%**
Standard Deviation		**0.50%**			**1.01%**			**2.22%**			**1.54%**	**0.63%**
Standard Deviation/ Average		**26.3%**			**41.2%**			**578.1%**			**138.8%**	**43.7%**

The growth in OM&A input quantity is computed as the change in the industry's OM&A costs minus the change in OM&A input prices (Table 6). In 2012, OM&A input quantity grew by 9.58%. This is more than twice the growth in OM&A input quantity in 2011 and is by far the most rapid annual change in OM&A input in any of the sample years. This increase was due to an 11.14% increase in OM&A expenses in 2012, which PEG discusses in the following chapter. On average, OM&A input increased by 1.70% per annum over the 2002-2012 period.

Capital quantity (Table 7) grew by 3.58% in 2012 from the previous year. This was more rapid than the trend in previous years. Capital input grew at an average annual rate of 1.56% between 2002 and 2012.

Overall input quantity (Table 8) grew by 5.99% in 2012. Overall input quantity grew more rapidly in 2012 than in any year between 2002 and 2011. On average, overall input quantity grew by 1.63% per annum over the 2002-2012 sample period.

Total factor productivity growth (Table 9) is equal to output quantity growth minus input quantity growth. Since output quantity and input quantity grew by 0.99% and 5.99%, respectively, in 2012, industry TFP declined by 5.00% in 2012 from the previous year. On average, industry TFP declined by 0.33% per annum over the 2002-2012 sample period. This compares with an average growth in industry TFP of 0.19% per annum over the 2002-2011 period.

As discussed, PEG was asked to test the sensitivity of industry TFP growth to OPA conservation programs. This sensitivity test is illustrated in Tables 10 and 11. Table 10 shows output quantity growth when the annual conservation savings from the OPA programs are added back into industry kWh deliveries in 2006 through 2012 (assuming 2012 net energy savings are equal to 2011 net energy savings). This scenario effectively shows what kWh deliveries would have been over this period in the absence of OPA programs. It can be seen that output quantity growth under this scenario would have averaged 1.36% per annum in the 2002-2012 period. This is six basis points higher than the 1.30% output quantity growth measured for the same period in Table 2.

Table 11 shows the TFP implications of this scenario. Input quantity growth is unchanged when the OPA program savings are added to the industry's kWh deliveries. Output quantity growth increases by six basis points when net energy savings are added to industry kWh

Table 6

OM&A Quantity Trends for Ontario Electric Distributors, 2002-2012

	OM&A Cost		OM&A Price Index		OM&A Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.000		100.000		100.000	
2003	104.040	3.96%	102.213	2.19%	101.787	1.77%
2004	105.063	0.98%	104.791	2.49%	100.259	-1.51%
2005	107.207	2.02%	108.156	3.16%	99.122	-1.14%
2006	110.827	3.32%	110.142	1.82%	100.622	1.50%
2007	119.051	7.16%	113.880	3.34%	104.541	3.82%
2008	123.955	4.04%	116.605	2.36%	106.303	1.67%
2009	126.116	1.73%	118.112	1.28%	106.777	0.44%
2010	126.854	0.58%	121.680	2.98%	104.253	-2.39%
2011	133.297	4.95%	123.730	1.67%	107.732	3.28%
2012	149.012	11.14%	125.683	1.57%	118.562	9.58%
Average Annual Growth Rate 2002-2012		**3.99%**		**2.29%**		**1.70%**

Table 7

Capital Quantity and Cost Trends for Ontario Power Distributors, 2002-2012

	Capital Cost		Capital Price Index		Capital Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.50	1.48%	100.47	0.47%	101.02	1.01%
2004	103.39	1.85%	100.66	0.19%	102.71	1.66%
2005	106.08	2.57%	101.59	0.92%	104.42	1.65%
2006	106.14	0.06%	100.84	-0.74%	105.26	0.80%
2007	111.43	4.86%	103.31	2.42%	107.85	2.44%
2008	115.45	3.55%	105.82	2.39%	109.11	1.16%
2009	117.08	1.40%	107.10	1.21%	109.32	0.19%
2010	121.66	3.83%	109.31	2.04%	111.30	1.80%
2011	123.45	1.46%	109.45	0.13%	112.76	1.30%
2012	121.49	-1.60%	103.92	-5.19%	116.87	3.58%
Average Annual Growth Rate 2002-2012		**1.95%**		**0.38%**		**1.56%**

Table 8

Input Quantity Trends for Ontario Electric Distributors, 2002-2012

	Input Quantity Index		Capital Quantity		O&M Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.30	1.29%	101.02	1.01%	101.79	1.77%
2004	101.79	0.48%	102.71	1.66%	100.26	-1.51%
2005	102.42	0.61%	104.42	1.65%	99.12	-1.14%
2006	103.51	1.06%	105.26	0.80%	100.62	1.50%
2007	106.62	2.96%	107.85	2.44%	104.54	3.82%
2008	108.08	1.36%	109.11	1.16%	106.30	1.67%
2009	108.39	0.29%	109.32	0.19%	106.78	0.44%
2010	108.61	0.20%	111.30	1.80%	104.25	-2.39%
2011	110.87	2.06%	112.76	1.30%	107.73	3.28%
2012	117.71	5.99%	116.87	3.58%	118.56	9.58%
Average Annual Growth Rate 2002-2012		**1.63%**		**1.56%**		**1.70%**

Table 9

TFP Index Calculation for Ontario Power Distributors, 2002-2012

	Output Quantity Index		Input Quantity Index		TFP Index	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.13	2.11%	101.30	1.29%	100.82	0.82%
2004	103.96	1.77%	101.79	0.48%	102.13	1.29%
2005	106.85	2.74%	102.42	0.61%	104.32	2.12%
2006	108.22	1.28%	103.51	1.06%	104.55	0.21%
2007	109.74	1.39%	106.62	2.96%	102.92	-1.57%
2008	110.61	0.79%	108.08	1.36%	102.34	-0.56%
2009	111.18	0.51%	108.39	0.29%	102.57	0.22%
2010	111.84	0.59%	108.61	0.20%	102.97	0.39%
2011	112.80	0.86%	110.87	2.06%	101.75	-1.20%
2012	113.92	0.99%	117.71	5.99%	96.79	-5.00%
Average Annual Growth Rate 2002-2012		**1.30%**		**1.63%**		**-0.33%**

Table 10

Output Quantity Trends for Ontario Power Distributors with Net Energy Savings Adjustment, 2002-2012

	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
Year	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Index**	**Growth**
2002	2,528,664		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.43%	15,124,270	1.13%	67,480,321,397	2.94%	102.13	2.11%
2004	2,647,118	2.15%	15,282,376	1.04%	68,588,997,365	1.63%	103.96	1.77%
2005	2,703,821	2.12%	15,710,004	2.76%	72,989,180,570	6.22%	106.85	2.74%
2006	2,748,114	1.62%	16,004,095	1.85%	72,296,481,577	-0.95%	108.37	1.42%
2007	2,781,589	1.21%	16,030,411	0.16%	77,681,926,413	7.18%	110.05	1.54%
2008	2,823,654	1.50%	16,040,362	0.06%	77,048,660,193	-0.82%	110.98	0.84%
2009	2,864,567	1.44%	16,095,983	0.35%	74,370,271,565	-3.54%	111.65	0.60%
2010	2,885,251	0.72%	16,172,034	0.47%	74,866,606,532	0.67%	112.37	0.64%
2011	2,919,186	1.17%	16,287,524	0.71%	75,150,956,582	0.38%	113.44	0.95%
2012	2,954,040	1.19%	16,391,549	0.64%	75,735,750,725	0.78%	114.57	0.98%
Average Annual Growth Rate 2002-2012		**1.55%**		**0.92%**		**1.45%**		**1.36%**

Table 11

TFP Index Calculation for Ontario Power Distributors with Net Energy Savings Adjustment, 2002-2012

	Output Quantity Index		Input Quantity Index		TFP Index	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.13	2.11%	101.30	1.29%	100.82	0.82%
2004	103.96	1.77%	101.79	0.48%	102.13	1.29%
2005	106.85	2.74%	102.42	0.61%	104.32	2.12%
2006	108.37	1.42%	103.51	1.06%	104.70	0.35%
2007	110.05	1.54%	106.62	2.96%	103.22	-1.42%
2008	110.98	0.84%	108.08	1.36%	102.69	-0.51%
2009	111.65	0.60%	108.39	0.29%	103.00	0.31%
2010	112.37	0.64%	108.61	0.20%	103.46	0.44%
2011	113.44	0.95%	110.87	2.06%	102.33	-1.10%
2012	114.57	0.98%	117.71	5.99%	97.33	-5.00%
Average Annual Growth Rate 2002-2012		**1.36%**		**1.63%**		**-0.27%**

deliveries. TFP growth is equal to the growth in output quantity minus the growth in input quantity, so the 2002-2012 industry TFP trend also rises by six basis points under this scenario, from -0.33% per annum to -0.27% per annum.

1.3 Econometric and Stretch Factor Results

PEG also updated the econometric model used to benchmark distributor costs to include 2012 data. Table 12 shows the cost measures used in our TFP and econometric analysis. Table 13 shows the econometric results for PEG's cost benchmarking model. Using the same econometric specification that was used in our May 2013 report, PEG found that the following variables were statistically significant drivers of distributor costs:

- Customer numbers
- The system capacity peak demand measure
- Retail kWh deliveries
- Average km over the 2002-2012 period
- The percent of customers added in the last ten years

All five variables were also found to be statistically significant cost drivers in our May 31, 2013 report. The undergrounding and service territory variables were not statistically significant cost drivers. This is also consistent with PEG's May 31, 2013 report, although these variables were found to be statistically significant in earlier work.

It should also be noted that the trend variable in Table 13 is equal to 0.0198 and is statistically significant. This compares with a trend coefficient of 0.012 in the analogous cost benchmarking model presented in PEG's May 31, 2013 report.[3] Because of the surge in costs in 2012, the coefficient on the trend variable increased by 78 basis points when the sample period was extended from 2011 to 2012. The reason is that 2012's dramatic increase in costs was not matched by similarly large changes in any output or business condition variables in 2012, so the large cost growth in that year was manifested in a higher trend rate of change in costs that is not associated with any particular cost driver.

[3] In both Table 10 and Table 12 of the May 31, 2013 PEG report, the trend coefficient was equal to 0.012. Table 12 was used to generate benchmarking evaluations in that report, although Table 10 is arguably more analogous to Table 10 in the current report since both are estimated using the full sample of 73 distributors in the industry.

Table 12

Cost Measures for Empirical Analysis

Industry TFP Growth	Included in Study?	Distribution Cost Benchmarking	Included in Study?
Candidate Capital Costs:		**Candidate Capital Costs:**	
Capital Benchmark Year: 1989*		Capital Benchmark Year: 1989*	
Taxes	No	Taxes	No
Transmission Substations > 50 KV Assets**	Yes	Transmission Substations > 50 KV Assets**	No
Gross Capital Expenditures	Yes	Gross Capital Expenditures	Yes
CIAC	No	CIAC	Yes
Smart Meter Expenditures	No	Smart Meter Expenditures	Yes
Candidate OM&A Costs:		**Candidate OM&A Costs:**	
Distribution OM&A (excluding bad debt expenses)	Yes	Distribution OM&A (excluding bad debt expenses)	Yes
High Voltage OM&A***	Yes	High Voltage OM&A***	No
Low Voltage Charges to Embedded Distributors****	No	LV Charges to Embedded Distributors****	Yes
Smart Meter Incremental OM&A*****	No	Smart Meter Incremental OM&A*****	Yes

Notes:

* Exceptions are Hydro One, Algoma Power, Canadian Niagara Power, Greater Sudbury Power, Innisfill Hydro and PUC Distribution, where data before 2002 were not available.

** Account Number 1815

*** Proxy High Voltage OM&A costs were calculated as the sum of OM&A in accounts 5014, 5015, and 5112

**** Excludes Regulatory Asset Recovery Charges

***** Account Number 1556, net of estimated amortization of smart meter expenditures

Table 13

Econometric Coefficients: Cost Benchmarking

VARIABLE KEY

Input Price:	WK =	Capital Price Index
Outputs:	N =	Number of Customers
	C =	System Capacity Peak Demand
	D =	Retail Deliveries
Other Business Conditions:	A =	2012 Service Territory
	U =	Percent Lines Underground
	L =	Average Line Length (km)
	NG =	% of 2012 Customers added in the last 10 years
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6379	97.3980
N*	0.3952	6.4560
C*	0.1857	3.0860
D*	0.1123	2.6480
WKxWK*	0.2551	8.6860
NxN*	-1.0303	-4.7910
CxC	-0.1380	-0.6670
DxD	0.1797	1.9180
WKxN	0.0185	1.0340
WKxC	0.0286	1.7180
WKxD	0.0003	0.0380
NxC*	0.6331	3.3920
NxD	0.1852	1.7550
CxD*	-0.3267	-3.1220
A	0.0191	1.1110
U	0.0036	0.2180
L*	0.2963	7.5610
NG*	0.0193	2.0070
Trend*	0.0198	12.6690
Constant*	12.983	285.515
System Rbar-Squared	0.985	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

By way of comparison, the trend coefficient in the Table 1 econometric results presented in this report is 0.0081. This estimate is nearly 120 basis points below the trend coefficient on the cost benchmarking model. For simplicity PEG's May 2013 report did not report a cost model that used the TFP cost specification as the dependent variable. PEG did perform this econometric analysis, however, and we found that when the same econometric models presented in Tables 10 and 12 of the May 2013 report were applied to the TFP cost specification, the trend coefficient was only 0.005. This value was 70 basis points below the trend coefficient on the cost benchmarking model presented in PEG's May 2013 report.

The trend coefficient on the TFP-based cost model therefore increased by about 30 basis points when the sample period was extended from 2011 to 2012, for the same reason previously explained for the cost benchmarking model. The trend coefficient does not, however, increase nearly as much on the TFP-based cost model as in the cost benchmarking model when the sample period is extended by a year. As a result, the gap between the trend coefficients on the benchmarking and TFP-based models increases from the 2002-2011 to the 2002-2012 period.

The econometric model presented in Table 13 was used to benchmark distributors' cost performance. As in PEG's previous work, the model was used to predict each distributor's costs given the values for the independent variables each experienced over the three most recent years. In this update, the three most recent years were 2010 through 2012. These cost predictions were then compared to the distributor's actual costs in the three most recent years. The difference between actual and predicted cost was taken to be an indicator of the distributor's cost performance relative to the rest of the Ontario electricity distribution industry. These cost performance rankings are presented in Table 14 along with their p-values, which represent the significance level on the test of the hypothesis that each distributor's predicted cost is equal to its actual cost.

PEG was asked to use these cost performance rankings to assign stretch factor values to each of the 73 distributors. The Board has determined that stretch factors will be based on PEG's econometric cost performance rankings, with the industry divided into five cohorts based on relative cost performance. Distributors whose actual costs are at least 20% below the costs predicted by PEG's cost model will be in the first cohort and assigned a stretch factor of zero. Distributors whose actual costs are between 15% and 20% below the costs predicted by PEG's cost model will be in the second cohort and assigned a stretch factor of 0.15%. Distributors whose actual costs are between 0 and 15% below the costs predicted by PEG's cost model will be in the third cohort and assigned a stretch factor of 0.3%. Distributors whose actual costs are between 0 and 15% *above* the costs predicted by PEG's cost model will be in the fourth cohort and assigned a stretch factor of 0.45%. Distributors whose actual costs are more than 15% above the costs predicted by PEG's cost model will be in the fifth cohort and assigned a stretch factor of 0.6%.

The assignment of stretch factors to individual distributors that results from this approach is presented in Table 15. It can be seen that there are five distributors in cohort one, seven distributors in cohort two, 18 distributors in cohort three, 26 distributors in cohort four, and 17 distributors in cohort five. The average stretch factor for the industry will be 0.37%.

Table 14

Difference Between Actual and Predicted Cost: Cost Benchmarking Model

Distibutor	Ranking	Actual minus Predicted Cost	P-Value
HYDRO HAWKESBURY INC.	1	-0.591	0.000
WASAGA DISTRIBUTION INC.	2	-0.364	0.007
NORTHERN ONTARIO WIRES INC.	3	-0.308	0.004
HALDIMAND COUNTY HYDRO INC.	4	-0.282	0.004
GRIMSBY POWER INCORPORATED	5	-0.206	0.027
HEARST POWER DISTRIBUTION COMPANY LIMITED	6	-0.182	0.060
ENERSOURCE HYDRO MISSISSAUGA INC.	7	-0.171	0.068
HORIZON UTILITIES CORPORATION	8	-0.165	0.068
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORAT	9	-0.160	0.072
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	10	-0.155	0.072
MILTON HYDRO DISTRIBUTION INC.	11	-0.154	0.206
HALTON HILLS HYDRO INC.	12	-0.153	0.085
LONDON HYDRO INC.	13	-0.141	0.094
NEWMARKET-TAY POWER DISTRIBUTION LTD.	14	-0.121	0.133
OSHAWA PUC NETWORKS INC.	15	-0.117	0.136
POWERSTREAM INC.	16	-0.110	0.168
ENTEGRUS POWERLINES	17	-0.103	0.167
E.L.K. ENERGY INC.	18	-0.088	0.206
KITCHENER-WILMOT HYDRO INC.	19	-0.087	0.208
LAKELAND POWER DISTRIBUTION LTD.	20	-0.084	0.216
HYDRO OTTAWA LIMITED	21	-0.065	0.279
HYDRO 2000 INC.	22	-0.046	0.346
COLLUS POWER CORPORATION	23	-0.041	0.350
BURLINGTON HYDRO INC.	24	-0.039	0.356
ESSEX POWERLINES CORPORATION	25	-0.022	0.417
LAKEFRONT UTILITIES INC.	26	-0.022	0.418
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	27	-0.019	0.427
HYDRO ONE BRAMPTON NETWORKS INC.	28	-0.012	0.456
NIAGARA PENINSULA ENERGY INC.	29	-0.009	0.466
PUC DISTRIBUTION INC.	30	-0.006	0.476
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	31	0.002	0.493
OTTAWA RIVER POWER CORPORATION	32	0.004	0.486
WESTARIO POWER INC.	33	0.004	0.484
NORTH BAY HYDRO DISTRIBUTION LIMITED	34	0.006	0.478
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	35	0.009	0.468
BLUEWATER POWER DISTRIBUTION CORPORATION	36	0.020	0.425

Table 14 (continued)

Difference Between Actual and Predicted Cost: Cost Benchmarking Model

Distributor	Ranking	**Actual minus Predicted Cost**	**P-Value**
NORFOLK POWER DISTRIBUTION INC.	37	0.022	0.419
BRANTFORD POWER INC.	38	0.032	0.382
WHITBY HYDRO ELECTRIC CORPORATION	39	0.037	0.363
VERIDIAN CONNECTIONS INC.	40	0.039	0.359
ST. THOMAS ENERGY INC.	41	0.040	0.355
COOPERATIVE HYDRO EMBRUN INC.	42	0.044	0.359
KINGSTON HYDRO CORPORATION	43	0.057	0.298
CENTRE WELLINGTON HYDRO LTD.	44	0.063	0.281
KENORA HYDRO ELECTRIC CORPORATION LTD.	45	0.070	0.261
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	46	0.074	0.245
WATERLOO NORTH HYDRO INC.	47	0.090	0.199
ORILLIA POWER DISTRIBUTION CORPORATION	48	0.091	0.198
GREATER SUDBURY HYDRO INC.	49	0.098	0.179
NIAGARA-ON-THE-LAKE HYDRO INC.	50	0.105	0.166
PARRY SOUND POWER CORPORATION	51	0.110	0.164
SIOUX LOOKOUT HYDRO INC.	52	0.121	0.155
ATIKOKAN HYDRO INC.	53	0.130	0.152
CANADIAN NIAGARA POWER INC.	54	0.135	0.104
ORANGEVILLE HYDRO LIMITED	55	0.136	0.102
ERIE THAMES POWERLINES CORPORATION	56	0.140	0.136
GUELPH HYDRO ELECTRIC SYSTEMS INC.	57	0.157	0.070
RENFREW HYDRO INC.	58	0.165	0.066
FORT FRANCES POWER CORPORATION	59	0.170	0.060
PETERBOROUGH DISTRIBUTION INCORPORATED	60	0.171	0.053
BRANT COUNTY POWER INC.	61	0.204	0.030
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	62	0.204	0.027
TILLSONBURG HYDRO INC.	63	0.204	0.029
WELLINGTON NORTH POWER INC.	64	0.204	0.032
ENWIN UTILITIES LTD.	65	0.228	0.019
MIDLAND POWER UTILITY CORPORATION	66	0.238	0.013
FESTIVAL HYDRO INC.	67	0.240	0.012
WEST COAST HURON ENERGY INC.	68	0.351	0.001
WOODSTOCK HYDRO SERVICES INC.	69	0.366	0.000
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	70	0.431	0.001
CHAPLEAU PUBLIC UTILITIES CORPORATION	71	0.437	0.000
ALGOMA POWER INC.	72	0.515	0.000
HYDRO ONE NETWORKS INC.	73	0.730	0.000

Table 15

Assigned Stretch Factor Values

Stretch Factor = 0%

GRIMSBY POWER INCORPORATED
HALDIMAND COUNTY HYDRO INC.
HYDRO HAWKESBURY INC.
NORTHERN ONTARIO WIRES INC.
WASAGA DISTRIBUTION INC.

Stretch Factor = 0.15%

ENERSOURCE HYDRO MISSISSAUGA INC.
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION
HALTON HILLS HYDRO INC.
HEARST POWER DISTRIBUTION COMPANY LIMITED
HORIZON UTILITIES CORPORATION
MILTON HYDRO DISTRIBUTION INC.
WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Stretch Factor = 0.30%

LONDON HYDRO INC.
NEWMARKET-TAY POWER DISTRIBUTION LTD.
OSHAWA PUC NETWORKS INC.
POWERSTREAM INC.
ENTEGRUS POWERLINES
E.L.K. ENERGY INC.
KITCHENER-WILMOT HYDRO INC.
LAKELAND POWER DISTRIBUTION LTD.
HYDRO OTTAWA LIMITED
HYDRO 2000 INC.
COLLUS POWER CORPORATION
BURLINGTON HYDRO INC.
ESSEX POWERLINES CORPORATION
LAKEFRONT UTILITIES INC.
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.
HYDRO ONE BRAMPTON NETWORKS INC.
NIAGARA PENINSULA ENERGY INC.
PUC DISTRIBUTION INC.

Stretch Factor = 0.45%

ATIKOKAN HYDRO INC.
BLUEWATER POWER DISTRIBUTION CORPORATION
BRANTFORD POWER INC.
CANADIAN NIAGARA POWER INC.
CENTRE WELLINGTON HYDRO LTD.
COOPERATIVE HYDRO EMBRUN INC.
ERIE THAMES POWERLINES CORPORATION
GREATER SUDBURY HYDRO INC.
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED
KENORA HYDRO ELECTRIC CORPORATION LTD.
KINGSTON HYDRO CORPORATION
NIAGARA-ON-THE-LAKE HYDRO INC.
NORFOLK POWER DISTRIBUTION INC.
NORTH BAY HYDRO DISTRIBUTION LIMITED
ORANGEVILLE HYDRO LIMITED
ORILLIA POWER DISTRIBUTION CORPORATION
OTTAWA RIVER POWER CORPORATION
PARRY SOUND POWER CORPORATION
RIDEAU ST. LAWRENCE DISTRIBUTION INC.
SIOUX LOOKOUT HYDRO INC.
ST. THOMAS ENERGY INC.
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
VERIDIAN CONNECTIONS INC.
WATERLOO NORTH HYDRO INC.
WESTARIO POWER INC.
WHITBY HYDRO ELECTRIC CORPORATION

Stretch Factor = 0.60%

ALGOMA POWER INC.
BRANT COUNTY POWER INC.
CHAPLEAU PUBLIC UTILITIES CORPORATION
ENWIN UTILITIES LTD.
FESTIVAL HYDRO INC.
FORT FRANCES POWER CORPORATION
GUELPH HYDRO ELECTRIC SYSTEMS INC.
HYDRO ONE NETWORKS INC.
MIDLAND POWER UTILITY CORPORATION
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
PETERBOROUGH DISTRIBUTION INCORPORATED
RENFREW HYDRO INC.
TILLSONBURG HYDRO INC.
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
WELLINGTON NORTH POWER INC.
WEST COAST HURON ENERGY INC.
WOODSTOCK HYDRO SERVICES INC.

2. 2012 Data Issues and Implications for Recommended Productivity Factor

2.1 Data Issues

The 2012 TFP results are anomalous when compared with the industry's annual TFP changes between 2002 and 2011. TFP declined dramatically in 2012 primarily because of the 11.14% surge in reported OM&A in that year. Output growth, in contrast, was somewhat greater than in recent years, which all else equal would tend to bolster TFP growth.

The 2012 TFP and econometric results were impacted by three issues with the 2012 data: 1) data were not available on embedded distributors' LV payments made to host distributors; 2) at least 13 distributors adopted international financial reporting standards (IFRS) for the first time in 2012; and 3) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A expense accounts. Of these three data issues, PEG's TFP results were most affected by the clearing of the deferral accounts to expense.

From 2006 through 2011, distributors recorded income from rate adders, capital amortization and incremental OM&A in smart meter deferral accounts. In 2012, many distributors applied for and were granted Board approval to move booked assets to meter account number 1860 and the other income and expense items to the relevant Trial Balance accounts. The Board has determined that incremental OM&A associated with smart meters, as well as smart meter capital expenditures, should not be reflected in the productivity factor to be used in 4th Gen IR. The reason is that these are one-time expenditures that are not consistent with the industry's long-run TFP experience and which will not be repeated during the term of the 4th Gen IR.

The relevant deferral account (account 1556) includes incremental OM&A as well as amortization (i.e. depreciation) associated with smart meter investments. PEG does not use amortization data in our TFP analysis, but the amortization expenses were not separately itemized for each distributor in account 1556. It was accordingly necessary to estimate the depreciation booked to account 1556 on smart meter investments. PEG estimated these values by applying our 4.59% composite depreciation rate to each distributor's annual smart meter expenditures, as reported on the supplemental data request. These estimated depreciation expenses were then netted out of the account 1556 balances that were "cleared" to the RRR Trial Balance accounts in the year that they were cleared. The resulting net figure was the estimate of incremental OM&A associated with smart meters, and those incremental OM&A costs were subtracted from PEG's cost measure used for the TFP analysis.

The data issues associated with IFRS were easier to manage. At least 13 distributors changed their gross fixed asset values in 2012 when they adopted IFRS. PEG had used differences in gross asset value (plus an assumed rate of annual asset replacement) each year to determine capital expenditures. These capital expenditures, in turn, entered into the formula used to estimate annual changes in capital input. Since 2012 gross asset value was impacted by the switch to IFRS in 2012, PEG used distributors' reported capital additions (from the PBR section of the RRRs) to determine capital expenditures for 15 distributors where using gross asset values would have led to negative capital expenditures for the year.[4]

The switch to IFRS also impacted reporting on contributions in aid of construction (CIAC). Under IFRS, the previously reported values for CIAC are reported as deferred revenue and appear on the liability side of the balance sheet in Account 2440. To determine the CIAC for 2012, for all distributors, PEG added the CIAC balances in account 1995 at the end of the year and the deferred revenue booked in account 2440 to determine a total CIAC balance at the end of 2012. The balance in 2011 was then subtracted from this sum. If this difference was positive, it was taken to be 2012 CIAC for that distributor. If the difference was negative, PEG used zero as the value for CIAC.

As discussed, 2012 data were not available on the LV charges paid by embedded to host distributors. PEG therefore assumed that these charges were unchanged in 2012 from the year before. The LV cost data can be easily updated when the 2012 amounts are provided.

2.2 Productivity Factor Implications

The 2012 update of the TFP results reduced the industry's estimated TFP trend to -0.33%, or -0.27% if savings from OPA conservation programs are added back into output growth. There are precedents for negative X factors in energy utility regulation. For example, a

[4] These distributors are Aitkokan Hydro, Brantford Power, E.L.K. Energy, Enersource Hydro Mississauga, Enwin Utilities, Grimsby Power, Guelph Hydro, Horizon Utilities, Hydro Hawkesbury, Hydro Ottawa, Niagara Peninsula, Orangeville Hydro, Parry Sound Power, Powerstream, and Whitby Hydro.

number of indexing plans approved for transmission utilities in Australia early in the previous decade had large negative X factors. These utilities were subject to a "building block" approach to incentive regulation, and all were undertaking extensive capital investment programs. Capital spending for transmission service is especially lumpy, and these utilities were entering a phase of their investment cycles that required large increases in capital spending just as their incentive regulation plans were being approved.

More recently, some electricity distributors in the UK now have negative X factors in their RPI-X rate adjustment plans. It must be recognized, however, that before these negative X factors were approved, the UK distributors had experienced very large price reductions (via very large X factors) during the preceding 10 or 15 years of their price controls. Some distributors' prices declined by more than 50% during this period in "real," inflation-adjusted terms. These price reductions reflected the substantial cost efficiencies these distributors had achieved under incentive regulation, and over the course of multiple price control reviews the UK distributors have still experienced X factors that are far larger, on average, than those that have been applied to distributors in Ontario.

In principle, it can be appropriate to have a negative X factor *if* industry-wide input quantity is systematically growing more rapidly than industry-wide output quantity and that trend is expected to persist. Recall from PEG's 2010 concept paper that TFP is not identical to efficiency, since efficiency change is a component of TFP change. It is never appropriate to assume that efficiency would decline, but TFP could still decline because of changes in other factors identified in PEG's TFP decomposition formula.

Notwithstanding the theoretical possibility that negative X factors may be appropriate in some circumstances, there are several reasons why PEG believes a negative productivity factor would not be appropriate in 4th Gen IR. One is that the Board is currently examining the application of revenue decoupling to electricity distribution. Not to prejudge the outcome of this Board examination, but it should be noted that a decoupling mechanism would largely address the impact of declining output on industry TFP and, by extension, industry revenue change. Furthermore, as discussed in PEG's May 2013 report, the main reason electricity distributors' TFP has slowed and become negative in recent years is because of the decline in distributor output, and a revenue decoupling mechanism would counter this trend.

A decoupling mechanism effectively breaks the link between distributors' revenues and the kWh volumes that are delivered to customers. Under current regulation, all else equal, distributor revenues fall when kWh deliveries decline. Revenue decoupling would sever (or at least greatly weaken) this relationship, so that revenue would remain constant when distributors' kWh output declines. Recall that revenue is, by definition, equal to price multiplied by output. Because decoupling allows revenues to remain constant even when output falls, decoupling effectively raises prices on distribution services to recover the revenues that would be lost when kWh decline.[5]

There may also be concerns associated with the rate riders and related rate recovery mechanisms that exist in Ontario. Some costs transferred to the 2012 Trial Balance data may have been previously reflected in and recovered by a rate rider. If it is true, however, it would not be appropriate for costs previously recovered through rate riders to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during the term of 4th Gen IR. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.

Finally, it is not clear that the negative 2002-2012 TFP trend is in fact industry-wide rather than the experience of a relatively small number of distributors. The Renewed Regulatory Framework for Electricity (RRF) will have multiple ratemaking options available to distributors. One of these options is designed to be "custom" to distributors with especially rapid capital investment needs. Although it is not clear which distributors will elect to file custom IR proposals, it is conceivable that distributors with historically high capital spending could depress industry-wide TFP trends, and thereby reduce the X factor in 4th Gen IR, and later choose to opt out of this ratemaking approach precisely because of their atypical capital requirements. This

[5] Although it is almost never interpreted in this way, revenue decoupling creates a kind of partial, "negative X factor" price adjustment when certain outputs fall. A revenue decoupling mechanism leads to price increases when designated outputs decline. A negative productivity factor leads to price increases (relative to inflation) when overall output declines and TFP growth becomes negative. Although a revenue decoupling mechanism is more narrow and targeted in scope, it effectively allows distributors to raise prices when their output declines.

Moreover, the same kWh (and perhaps kW) outputs that are targeted by the decoupling mechanism will also be included in the measure of industry TFP growth. Having two price adjustment mechanisms potentially impacted by the same underlying issue of declining output growth creates the potential for double counting. If a negative productivity factor is approved, it will allow distributors to increase prices relative to inflation largely because of increasingly slow and declining growth in kWh per distribution customer. If revenue decoupling is approved, it will allow distributors to raise prices as long as this existing, trend decline in kWh per customer *persists* while the revenue decoupling and IR mechanisms are in effect.

would lead to higher price adjustments under 4th Gen IR than are warranted for distributors with more typical capital requirements.[6]

In sum, the implications of a negative productivity factor are particularly troubling given the Ontario regulatory environment. The possibility of revenue decoupling, the potential concerns associated with rate riders, and the multiple ratemaking options in the RRF create a significant probability that a negative productivity factor would either double-count costs that are being recovered elsewhere, or reflect the experience of a small number of distributors with atypical investment needs who elect to opt out of 4th Gen IR altogether. The latter result would be counter to the Board's intended purpose of 4th Gen IR, which is to be appropriate for most distributors in the Province who do not have high or variable capital requirements. Because of these concerns, and notwithstanding the current, tentative estimate of negative TFP growth for the Ontario electricity distribution industry, PEG recommends that the productivity factor in 4th Gen IR be no lower than zero.

[6] It should be noted that neither the Australian transmission utilities nor the UK power distributors had the option of choosing among different regulatory mechanisms.