[Given the nature of the PEG evidence, interrogatories have not been assigned to individual issues.]

SCHOOL ENERGY COALITION IR #1

PEG-SEC-1

[p. 5] Please provide a copy of the cited paper for Lawrence Berkeley National Laboratory.

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

Here is a link to the cited paper.

https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

SCHOOL ENERGY COALITION IR #2

PEG-SEC-2

[p. 6] Please explain why it is reasonable to exclude productivity gains from a capital pass-through mechanism. Please identify the risks to the customers of this proposal.

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

Capital cost pass-through mechanisms generally weaken utility incentives to contain capital expenditures (“capex”). The mechanism proposed by Hydro One protects customers, strengthens capex containment incentives, and reduces regulatory cost by making costs of capex exceeding proposed levels ineligible for recovery. The proposed passthrough of capex underspends weakens Hydro One’s incentive to exaggerate its requirements but also weakens its incentives to underspend. The proposed exemption of underspends due to productivity gains strengthens incentives to underspend but encourages strategic behavior. For example, the Company has an incentive to misrepresent the extent of true productivity gains. Regulatory cost would be increased substantially.

A simpler alternative to the Company’s proposal is to share underspends mechanistically using a predetermined formula. See, for example, the sharing of total expenditure variances in Britain’s RIIO approach to power distributor regulation.

There are also precedents for this general approach in Canada. The BCUC approved several Certificates of Public Convenience and Necessity for several large projects that were conditional on the sharing of cost variances. Some of these mechanisms shared cost overruns or underspends that were outside of a deadband of +/- 10% evenly between the utility and customers.

In the United States, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas all have obtained special ratemaking treatments to recover the cost of full AMI deployment. Each approved AMI ratemaking treatment took the form of a capex tracker with a preapproved multiyear capex forecast. The deployment plans allowed recovery of capital costs with an offset for O&M savings.

If each company’s actual cost to deploy AMI was in line with the approved forecast, there would be no subsequent prudence review. Diverse variance treatments were allowed for these plans. Southern California Edison’s AMI deployment tracker featured an asymmetric sharing mechanism wherein 90% of the first $100 million in excess of the approved forecast was charged to ratepayers without the need for a further prudence review. Exceptions to the cost caps were made for *force majeure* events, changes in the project’s scope due to government or regulatory activity, and delays in Commission approval. The treatment of variances from forecasted cost for San Diego Gas & Electric was similar, as 90% of the first $50 million over the budget would be granted to the Company without a further prudence review. The same exceptions to the cap as described for Southern California Edison applied to San Diego Gas & Electric’s AMI tracker. San Diego Gas & Electric’s AMI tracker also authorized a sharing of the first $50 million under the budget, with 10% going to the company. Southern California Gas' AMI tracker was similar to San Diego Gas & Electric's. However, the Southern California Gas AMI tracker lacked a *force majeure* provision and had a larger amount at risk. The company could recover 50% of the first $100 million above the budget and 10% of the first $100 million under the budget without a further prudence review.

SCHOOL ENERGY COALITION IR #3

PEG-SEC-3

[p. 11] Please discuss the pros and cons of using average weekly earnings vs. fixed weighted average hourly earnings to measure labour inputs in Canadian productivity research.

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

The fixed-weighted average hourly earnings ("AHE") are a more accurate measure of the trend in Ontario labor prices than average weekly earnings because they are less prone to aggregation bias. For example, they are less sensitive to the amount of overtime hours worked. AHEs are also more stable. Since the AHE grows a little more briskly, their use in productivity research will increase estimated industry productivity trends. However, since HONI is likely to be subject to a consolidated revenue cap index with a base TFP trend of 0% in any event, customers will not benefit from using AHE to measure productivity growth in the short run. Utilities in the future will have a reasoned basis for including the AHE in the inflation measure. Hydro-Québec recently proposed to include the AHE in the inflation measure of the revenue cap index for its distribution services. Please see our response to HONI-62 for a table comparing AHEs and AWEs.

SCHOOL ENERGY COALITION IR #4

PEG-SEC-4

[p. 12] Please describe any academic or technical work that has been published that seeks to explain or quantify the lag between CDM-driven declines in volumes or peak demand, and the decline of OM&A or capital costs of wires companies.

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

PEG is unaware of any academic or other technical work on the lag between CDM-driven declines in volumes or peak demand and the decline of OM&A or capital costs of wires companies. One reason is that the decline in costs of wires services due to CDM has thus far been negligible. Here are some reasons why.

a) Transmission and distribution ("T&D") costs depend more on peak demand than on delivery volumes. OM&A expenses are driven more by the number of customers served than by system use. Environmental damage depends more on volumes.

b) The effect of peak load management on T&D capital cost is reduced in the short run by the fact that utilities have limited opportunities to reduce the cost of existing systems.

c) Many utilities do not have advanced metering infrastructure.

d) Utilities are unsure of the future trend in peak demand. For example, OEB, provincial, and federal government policies concerning CDM, rate designs, appliance efficiency standards, and building codes may change. So can local economic growth, technology, and customer attitudes about CDM, distributed generation and storage, and electric vehicles.

e) Time-sensitive pricing of distribution services is risky for utilities that don't have revenue decoupling.

f) Due chiefly to reasons a) – e), CDM programs in North America have focused on energy savings rather than the peak demand savings. Even utilities with AMI have been slow to institute time-sensitive pricing of their transmission and distribution services. Current rate designs therefore do not especially encourage customers to make peak load reductions that can reduce T&D costs.

g) Distributed solar generation has reduced delivery volumes more than peak demand in those jurisdictions where it is prevalent.

h) Transmission capex has remained high in many regions of North America in order to access remote renewable (e.g., wind and water) resources and improve the functioning of bulk power markets.

i) Transmission services of many U.S. electric utilities are regulated by comprehensive cost trackers called formula rate plans that weaken cost containment incentives.

SCHOOL ENERGY COALITION IR #5

PEG-SEC-5

[p. 13] Please confirm that, while price cap indices are commonly used, revenue cap or revenue cap per customer indices are a closer match to cost escalation of wires companies, because the costs of those companies are driven more by customer numbers than by throughput or peak in the short and medium term. Please comment on whether the move in Ontario to fixed residential prices results in price cap more closely tracking cost inputs.

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

Dr. Lowry notes that revenue cap indexes should be designed to track cost trends, whereas the design of price cap indexes should consider, additionally, how trends in the billing determinants that drive base rate revenue differ from trends in scale-related cost drivers. Econometric research has consistently found the number of customers to have a higher distribution cost elasticity than delivery volumes or peak demand. The two econometric benchmarking models in the current proceeding are illustrative. Dr. Lowry believes that this reflects the fact that the number of customers served is an important cost driver in its own right and is also highly correlated with the expected aggregate coincidental peak demands of individual circuits. Revenue cap indexes therefore typically have a customer growth escalator.

Revenue cap indexes are actually as popular as or more popular than price cap indexes for energy utilities. Jurisdictions where they are used include Alberta (gas only), Australia, California, and Massachusetts. The Regie de l'Energie in Québec has ordered Gaz Metro and Hydro-Québec Distribution to operate under revenue per customer indexes prospectively.

The move to full fixed residential prices in Ontario should cause revenue growth to track cost growth more closely than rate designs with high volumetric charges. However, full fixed-rate designs do not address the long-run cost impact of residential peak demand. Time-sensitive pricing may continue and expand for larger-volume customers.

SCHOOL ENERGY COALITION IR #6

PEG-SEC-6

[p. 15, 34] Please explain why it is not appropriate to use the 0.61% productivity factor for OM&A to escalate OM&A expenditures during the Hydro One IRM period (i.e. I - 0.61% - 0.45%). Please explain why TFP is relevant at all in a proposed structure where capital is "determined on a cost of service basis". Why is PFP for OM&A not more appropriate?

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

Dr. Lowry believes that separate ratemaking treatment of OM&A and capital revenue is generally defensible and is especially defensible for utilities that are already requesting this approach by seeking supplemental capital revenue through such means as ICMs or C factors. A revenue cap index for OM&A expenses can reflect the productivity of OM&A inputs and possibly also OM&A input prices. Customers benefit if an OM&A revenue cap index grows faster.

There are numerous precedents for the separate ratemaking treatment of OM&A expenses and capital costs in multiyear rate plans.

- One form of this can be found in British Columbia, where several generations of IRMs for FortisBC and FortisBC Energy (formerly West Kootenay Power and Terasen Gas, respectively) have featured separate indexes for OM&A expenses and capital revenue.[1]

- Several utilities, including Hawaiian Electric, Hawaiian Electric Light, Maui Electric, and Southern California Edison have operated under IRMs with hybrid revenue caps where OM&A revenue is indexed while the revenue requirement for capital cost is forecasted. The indexing may in some cases include a productivity offset. This is implicit in California, as customer growth has been assumed to be offset by productivity, and explicit in Hawaii, as labor O&M costs are reduced by a 0.76% productivity offset.

- The Australian Energy Regulator escalates revenue for OM&A expenses using a "base, step, trend" methodology, while revenue requirements for capital cost are based on forecasts. The Australian "base, step, trend" methodology escalates normalized OM&A expenses in the historical base year for the expected trends in inflation, productivity, and output growth, with step adjustments to account for new initiatives approved by the regulator. The resulting total revenue requirement over the plan term is then smoothed using expected Inflation and an X factor.

[1] Supplemental revenue is available to address capital costs of specific types of plant additions.

- Another kind of hybrid attrition relief mechanism has been used in recent Vermont rate plans. The revenue requirements for OM&A expenses of gas and electric power distributors are indexed, while revenue requirements for new plant additions are forecasted and approved by the regulator in annual proceedings.

- Still another kind of hybrid attrition relief mechanism combines a rate freeze for most costs of base rate inputs (including costs of old plant) with trackers to address some or all of the company's capital costs resulting from new plant additions. This ratemaking treatment has been approved for numerous U.S. utilities over the years, including Virginia Electric Power and Appalachian Power, AEP-Ohio, the First Energy Ohio companies, Arizona Public Service, electric services of Public Service of Colorado, Florida Power & Light, Duke Energy Florida, Cleco Power, and MidAmerican Energy.

Unfortunately, there is not high-quality evidence in this proceeding of the OM&A productivity or input price trends of Ontario power distributors. The calculations in Table 1 of Dr. Lowry's report were not presented as a definitive update and upgrade of PEG's research for the Board in 4th Generation IRM. The best available evidence is PEG's recent study of the productivity trends of U.S. power distributors. PEG reported that the OM&A productivity of a large sample of U.S. power distributors averaged 0.39% from 2001 to 2014.[2] The difference between OM&A and capital productivity trends seems to have been larger in recent years for gas distributors than for power distributors.

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

SCHOOL ENERGY COALITION IR #7

PEG-SEC-7

[p. 18] Is it reasonable and methodologically sound to compare Table 1 and Table 2, and conclude that Hydro One has 192 basis points worse (slower) productivity than the Ontario industry on OM&A (but improving strongly), and 268 basis points worse productivity than the Ontario industry on capital (and getting worse)? If the answer is yes, with or without qualifications, are there steps the Board can take to identify the reasons for that relatively poor productivity performance relative to peers?

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

PEG's research suggests that, using similar TFP indexes, HON's total factor productivity growth averaged -2.31% annually from 2003 to 2015. This was 206 basis points below the -0.25% trend for other Ontario power distributors. OM&A productivity growth was about 142 basis points below the norm on average while capital productivity growth was about 242 basis points below the norm. PEG's econometric benchmarking study indicated a decline in cost performance from +6.9% over the benchmark in 2002 to +23.2% in 2015. The average annual decline in Hydro One's score over this period was (23.2-6.9)/13 = 125 basis points. The OEB's activities and program benchmarking program may ultimately shed more light on particular high cost areas of Hydro One and other distributors.

SCHOOL ENERGY COALITION IR #8

PEG-SEC-8

[p. 29] Is it possible to develop a program benchmarking peer group for Hydro One that has similar peers? Alternatively, is it possible to use econometric approaches to compare the cost components with other distributors that are not sufficiently similar to be peers?

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

Dr. Lowry notes that it is possible to benchmark Hydro One's cost at a more granular or functional level. PEG took a step in this direction in its recent study for Alberta's Utilities Consumer Advocate.[3] Byproduct benchmarking results were obtained for Hydro One's capital cost, capex, and OM&A expenses as well as its total cost. This was done with both econometric models and peer groups of utilities with low customer density which included FortisAlberta, ATCO Electric, Algoma Power, and several U.S. utilities. The OEB has initiated a project to develop its own activities and program benchmarking capabilities.

[3] Pacific Economics Group Research (2018). *Benchmarking the Performance of Alberta Power Distributors*, for Utilities Consumer Advocate of Alberta, February 2018.

SCHOOL ENERGY COALITION IR #9

PEG-SEC-9

[p. 31] Please advise whether it is possible, on the evidence, to identify the portion of the proposed C factor that is capturing the cost of system expansion, as proposed by Hydro One. If it is possible to identify that component, please compare the impacts of that approach to using an express growth factor as proposed by PEG.

Response to SEC-9: The following response was provided by PEG.

PEG does not believe that it is possible based on the filed evidence to accurately identify the portion of the proposed C factor that captures the cost of system expansion. One problem is that Hydro One's calculation of the proposed C factor, as provided in Table 1 of Exhibit A, Tab 3, Schedule 2 was not provided in Excel format.

A second concern PEG has is that HON's plant additions do not appear to be sufficiently disaggregated to show only the plant additions that correspond to PEG's proposed growth factor. For example, Hydro One's development plant additions appear to include a substantial amount of "system capability reinforcement capex" and PEG is uncertain as to whether this capex aligns with PEG's proposed growth factor.

SCHOOL ENERGY COALITION IR #10

PEG-SEC-10

[p. 32] Please explain why the growth factor would not be reduced for the relative impact of growth on OM&A costs, as estimated by PEG in the Oshawa Custom IR proceeding (i.e. 1% growth equals 0.44% increase in OM&A).

Response to SEC-10: The following response was provided by PEG.

In the Oshawa Custom IR proceeding, Dr. Lowry outlined an escalator for OM&A revenue ("ROMA") of general form

$$\textit{growth ROMA} = \textit{Inflation} - (\textit{trend Productivity}^{OM\&A} + \textit{Stretch}) + \textit{growth Outputs}. \qquad [1]$$

It implement this formula, OM&A productivity must be measured using a consistent Outputs index. The realization of scale economies is a component of productivity growth.

$$\textit{Growth Productivity} = \textit{growth Scale Economies}^{OM\&A} + \textit{growth Other Productivity}^{OM\&A} \qquad [2]$$

Suppose now that 1% growth in Outputs produced 0.44% cost growth. Then there would be substantial scale economies and productivity growth can be decomposed as

$$\textit{trend Productivity} = 0.56\%\ x\ \textit{growth Outputs} + \textit{growth Other Productivity}^{OM\&A}. \qquad [3]$$

The scale escalator of 0.44 x growth Outputs that is discussed in the question is tantamount to reducing the X factor by the scale economy component from the productivity trend. Equivalently, productivity must be measured as 0.44% growth Outputs – growth Inputs$^{OM\&A}$.

Consider also that the number of customers is highly correlated with the expected aggregate peak demands of distribution networks. If there is not a peak demand variable in the output index, 0.44 x Customers would then be an understatement of the effect of output growth on cost.

SCHOOL ENERGY COALITION IR #11

PEG-SEC-11

[p. 35] Please confirm that the capital productivity factor identified in past spending, if applied in the IRM either separately or as part of TFP, implicitly assumes that future capital spending will be at the same relative levels as the capital spending during the productivity measurement period.

Please confirm that an additional C factor is only justified if capital spending, relative to outputs, is expected to be higher in the future than in the past.

Response to SEC-11: The following response was provided by PEG.

Rate and revenue cap indexes based on productivity research will tend to provide escalation commensurate with industry productivity growth trends. The productivity research is not always intended to produce a *forecast* of future productivity growth. A comprehensive rate or revenue cap index provides escalation commensurate with recent *total* factor productivity growth. If a utility requests supplemental revenue for capital, it is effectively asking for separate ratemaking treatment of OM&A and capital revenue. It is then reasonable to consider how industry trends in the productivity (and possibly also the prices) of capital and OM&A inputs differ. The index logic for this treatment is as follows.

$$\begin{aligned}
\text{growth TFP} &= \text{growth Outputs} - \text{growth Inputs} \\
&= \text{growth Outputs} - (\text{cost share}^{\text{Capital}} \times \text{growth Inputs}^{\text{Capital}} + \text{cost share}^{\text{OM\&A}} \times \text{growth Inputs}^{\text{OM\&A}}) \\
&= \text{cost share}^{\text{Capital}} \times (\text{growth Outputs} - \text{growth Inputs}^{\text{Capital}}) + \\
&\quad\ \text{cost share}^{\text{OM\&A}} \times (\text{growth Outputs} - \text{growth Inputs}^{\text{OM\&A}}) \\
&= \text{cost share}^{\text{Capital}} \times \text{growth Productivity}^{\text{Capital}} + \text{cost share}^{\text{OM\&A}} \times \text{growth Productivity}^{\text{OM\&A}}
\end{aligned}$$

Supplemental revenue can be based on the extent to which proposed capital cost exceeds the funding provided by the revenue requirement in the first year of the plan as escalated for inflation, any growth, and the capital productivity trend. The supportive research once again may or may not be forward-looking.

SCHOOL ENERGY COALITION IR #12

PEG-SEC-12

[p. 37] Please advise whether rebasing plus 4th Generation IRM with an ACM would approximate the rate trajectory that PEG has proposed. If there are material differences, please advise.

Response to SEC-12: The following response was provided by PEG.

Dr. Lowry notes that his proposal differs in several ways from 4th Generation IRM, including the use of a revenue cap index rather than a price cap index. He agrees that the advanced capital module ("ACM") provides a useful precedent for the capital cost treatment he favors. The ACM…

- is based on a multiyear capex forecast;
- considers the revenue that the initial revenue requirement and revenue growth make available for capex;
- uses a materiality threshold and deadband to make a percentage of otherwise-unfunded capex ineligible for supplemental revenue.

The materiality threshold is rationalized on the grounds of reducing regulatory cost by prohibiting ICMs for small revenue shortfalls.

Dr. Lowry proposes a C factor that

- is based on a multiyear capital cost proposal adjusted for industry productivity growth;
- considers the revenue available to fund capital consisting of the 2018 revenue requirement as escalated by the RCI;
- uses a materiality threshold and deadband to make a percentage of otherwise-unfunded capital cost ineligible for extra revenue.

The materiality threshold reduces regulatory cost by prohibiting ICMs for small revenue shortfalls. It also strengthens capex containment incentives, discourages strategic bunching of capex, and protects customers from an asymmetrical preoccupation with capital cost problems that effectively prohibits them from receiving the benefit of industry productivity growth in the longer run.

SCHOOL ENERGY COALITION IR #13

PEG-SEC-13

[p. 38] If the Board does not end the pension and OPEBs DVAs, is it possible to calculate an appropriate adjustment to the IRM formula to reflect the fact that this is a pass-through? If so, how would that be done?

Response to SEC-13: The following response was provided by PEG.

The TFP trend could in principle be recalculated to exclude pension and other benefit expenses. However, this is difficult to do in Ontario due to inconsistencies in the way utilities itemize these expenses. Itemizations of pension and benefit expenses are more consistent in the United States, so that these expenses can be easily removed from productivity calculations. This is another reason to consider U.S. productivity trends in the design of X factors for distributors in Ontario.

SCHOOL ENERGY COALITION IR #14

PEG-SEC-14

[p. 42] After a period of high replacement capex, is it generally true that, in addition to capital productivity improving because of depreciation, etc., OM&A productivity also improves as the newer capital reduces operating costs?

Response to SEC-14: The following response was provided by PEG.

Dr. Lowry notes that the potential of high replacement capex to bolster OM&A productivity in the power distribution industry is not well known and has not been frequently emphasized in discussions of this industry.