Report to the Ontario Energy Board

Activity and Program Benchmarking of Ontario Electricity Distributors

December 18, 2018

Mark Newton Lowry, Ph.D.
President

David Hovde
Vice-President

Matthew Makos
Consultant II

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601

Madison, Wisconsin USA 53703

608.257.1522   608.257.1540 Fax

Table of Contents

1. Introduction and Summary

1.1 Introduction

Statistical benchmarking has a growing role in energy utility regulation. Benchmarking can encourage utilities to achieve long-term performance gains. Benchmarking can also reduce the cost of the numerous rate applications that the Ontario Energy Board ("OEB") must handle and increase their effectiveness. Strategic cost deferrals can be discouraged that reduce the benefits to customers of multiyear rate plans.

The OEB currently uses total cost benchmarking in electricity distributor regulation to set the stretch factors of price (and, for some, revenue) cap indexes and to appraise proposed revenue requirements during the periodic rate rebasings of these companies. Benchmarking is also used by regulators in several countries overseas (e.g., Australia, Great Britain, and Germany).

Various methods are used in benchmarking. Indexing (e.g., unit cost) and econometric methods have been favored by regulators in Australia, Great Britain, and North America. Data envelopment analysis ("DEA") is favored by several regulators in continental Europe. All of these methods can be used to appraise utility costs at various levels of granularity, from total cost to the costs of specific activities or programs.

The OEB set forth in its *2018-2021 Business Plan* four strategic directions. These include "enhancing utility performance" and "enhancing regulatory effectiveness."[1] Activity and program benchmarking ("APB") is included in the OEB's plan for realizing these goals.[2] APB will also support the 2017 Long-Term Energy Plan ("LTEP") of Ontario's provincial government. The LTEP calls for the OEB to promote efficiencies and cost reductions and make utilities more accountable to their customers. Enhanced use of benchmarking is expected to find inefficiencies in the electricity distribution sector, which will lead to cost reductions for customers.

The OEB has retained Pacific Economics Group Research LLC ("PEG") to assist it in the APB project. PEG is a leading provider of statistical research on energy utility performance. Our diverse

[1] Ontario Energy Board, *2017 to 2020 Business Plan*, p. 12.

[2] Ibid., p. 18.

client base includes utilities, regulators, government agencies, and consumer groups.

PEG has been asked to analyze alternative approaches to APB and recommend approaches for inclusion in the OEB's regulatory processes which will enhance the effectiveness of monitoring distributors' cost performance. The benchmarking methods appraisal included unit cost and productivity indexing, econometric cost modelling, and DEA. The unusually large number of distributors that must be regulated in Ontario was a salient consideration in the analysis. APB initiatives in other jurisdictions (e.g., Australia and Great Britain) have been surveyed. We considered appropriate granular costs for benchmarking after examining further the strengths and weaknesses of available data. A constructive consultation was undertaken with some stakeholders. PEG has also done some preliminary empirical research to support APB. Results of this research are encouraging (e.g., high confidence levels exhibited in some preliminary econometric cost models).

This is a report on our APB research to date. It is intended as a companion to the report prepared by OEB staff. Following a high-level summary of results, Section 2 provides an introduction to APB. Precedents for APB in other jurisdictions are discussed in Section 3. Section 4 considers alternative APB methods. Section 5 discusses data issues that are pertinent in developing an Ontario APB framework. An illustrative proposal for an APB framework is set forth in Section 6. An Appendix provides additional details on selected topics.

1.2 Summary

Key findings of our review are as follows.

1.2.1. The Promise of APB

APB has many potential uses in OEB regulation. Utilities can learn about areas where their performance is mediocre or deficient and be challenged to do better. Ostensibly superior firms can be queried concerning their operating practices. Knowledge of the capital cost [and/or capital expenditure ("capex")] performance implicit in proposed capital revenue requirements is useful in appraising proposals for Custom IR plans and incremental capital modules ("ICMs"). APB may also provide useful corroboration of the reasonableness of the OEB's *total* cost benchmarking. The value of APB can increase over time as experience is gained and data improve.

1.2.2. APB Challenges

Challenges can be encountered in an APB initiative. Granular costs may be itemized inconsistently between utilities. There are many more individual costs to benchmark than in a *total* cost study and accurate benchmarking of granular costs can sometimes be complicated. New data must sometimes be gathered. These challenges do not make APB impractical but should be considered when designing an APB framework.

1.2.3. APB Precedents

APB is used today by regulators in other jurisdictions that notably include Australia and Great Britain. Unit cost metrics are frequently used in this research. Australia has a particularly energetic program of data gathering to support benchmarking which includes extensive cost itemization and many cost driver variables. In both countries, samples of data on utility operations which can be used in benchmarking are smaller than in Ontario. Accurate benchmarking of capital cost (e.g., depreciation and the return on the value of rate base) is less feasible. These constraints have encouraged a focus on capital (and total) *expenditures* and limited use of econometric benchmarking.

1.2.4. Data Considerations

The OEB requires that each distributor itemize its data on OM&A expenses in an annual Reporting and Recordkeeping Requirements ("RRR") filing by activities such as distribution, billing and collection, and administrative and general expenses. Distributors have reported some costs inconsistently at more granular levels.

Currently available RRR capital data permit benchmarking of each distributor's *total* capital cost and capex but not cost itemizations. However, more itemized data are available from distributors. Accurate benchmarking of many itemized OM&A expenses is already feasible. APB will require some additional data reporting and improvement of cost itemization in accordance with OEB accounting requirements. It makes sense to limit data requests and make the most of data that are already gathered.

1.2.5. APB Methods

Unit cost methods may be featured in the OEB's APB program. These methods are preferred by utilities and may therefore encourage use of APB results in cost management. Unit cost methods are used for APB in other jurisdictions.

Econometric cost research can complement unit cost analysis. For example, econometric research on the drivers of cost can provide the basis for combining multiple relevant scale variables into a single scale index for unit cost comparisons. Econometric research can also test the relevance of additional business conditions and thereby gauge the need for custom unit cost peer groups and, where necessary, guide peer group selection. Econometric benchmarking can provide a check on unit cost results and has special advantages in the appraisal of capex.

1.2.6. Preliminary Empirical Results

We have undertaken some preliminary research to explore the potential of unit cost and econometric research to support effective APB in Ontario. Draft software has been developed to calculate and disseminate unit cost results. We have developed econometric cost models for OM&A expenses, some major components thereof, total capital cost, and total capex. The explanatory power of these models was generally quite high at the initial stages of disaggregation. Explanatory power tends to decline, however, when granularity increases.

Examination of individual models reveals that it is possible to identify numerous cost driver variables with statistically significant and plausibly signed parameter estimates. The results suggest that the accuracy of unit cost benchmarking can sometimes be improved with multidimensional scale indexes and consideration of additional business conditions. Trend variable parameters are useful for ascertaining how unit costs should change over time.

1.2.7. Illustrative APB Framework

PEG has developed an illustrative APB framework for the consideration of the OEB and stakeholders to stimulate thinking and discourse. This framework is consistent with our analysis. We note that benchmarking can be undertaken soon with reasonable accuracy and minimal new data collection for cost categories that include total OM&A expenses, some major components thereof, total capital cost, total capex, and specified more granular OM&A and capital activities or programs. It also makes sense to consider a limited number of more granular cost categories initially such as the costs that OEB staff have shortlisted in their paper.

Our analysis also identifies some additional data that would help the OEB to realize the full potential for APB. Data on gross plant additions and accumulated amortization and depreciation could be itemized by major asset category. Total gross plant additions could be itemized into the system access, system renewal, system service, and general categories used in DSPs. More effort is needed by distributors to ensure that costs in RRR reports, rebasing applications, and DSPs are itemized correctly and consistently. Some additional data on external business conditions and the character of the capital stock (e.g., system age) would also be useful.

A balance of considerations suggests that the OEB move expeditiously to develop an APB framework and to consider results in ratemaking but nonetheless use results cautiously in the early years. The accuracy of APB should improve with accumulating data and experience.

2. Activity and Program Benchmarking

2.1 The Basic Idea

The goal of APB is to benchmark subsets of the costs that distributors incur. These subsets are sometimes called “granular” costs. The focus may be activities defined by itemizations of cost that utilities report to regulators (e.g., distribution operation) or certain programs (e.g., substation refurbishment). Program costs do not always match the itemizations on regulatory filings. Various tools are available for APB including unit cost metrics, econometric models, and engineering models. It is sometimes appropriate to use multiple methods in the same study. In the English-speaking world, unit cost methods are most popular. Alternative methods are discussed in Section 4.

2.2 APB Pros and Cons

APB has many potential benefits in OEB regulation.

- The costs utilities incur for each activity or program should be efficient as well as their total cost. A utility with low distribution costs may, for example, nevertheless have unacceptably high billing and collection costs. APB can help utilities learn about areas where their performance is mediocre or deficient so that they are challenged to perform well in all areas of their business.
- As cost categories narrow, superior performance is more likely to be traceable to particular operating practices. Ostensibly superior firms can be queried concerning the practices they use. Granular cost benchmarking can therefore shed light on good operating practices. Private benchmarking consultancies facilitate discussions like these but participation is less affordable for smaller utilities.
- Knowledge gained from APB can permit the OEB to fast-track some areas of proposed revenue requirements while subjecting other areas to continued scrutiny.
- Knowledge of the capital cost (and/or capex) performance implicit in proposed capital revenue requirements is useful in appraising proposals for Custom IR plans and incremental capital modules (“ICMs”).
- APB provides useful corroboration of the reasonableness of the OEB’s *total* cost benchmarking.

- Areas can be identified where utilities itemize reported costs incorrectly.
- Some of the work required to make APB operational can reduce the cost of updating and upgrading the OEB's *total* cost benchmarking program if such a program is needed for 5^{th} GIR. For example, new data on business conditions that are gathered APB may also be useful in total cost benchmarking.
- Methods and skills developed in this project can potentially be applied in the future to Ontario electricity transmission and gas utilities.

Some challenges encountered in APB are also notable.

- The number of cost components that must be separately benchmarked increases with granularity.
- Accurate benchmarking of granular costs is at least as challenging as benchmarking of total costs for reasons that include the following.
- As granularity increases, there is more need for utilities to divide reported costs between activities. Itemization of cost involves time and effort, and the allocation of some costs between activities and programs is arbitrary. Enforcement of consistent itemization involves work for regulators as well and may not be vigorous. For these reasons, there may thus be inconsistencies between utilities and over time in the itemization of reported costs.
- Since some inputs are substitutes for others, benchmarking only one of a set of interrelated costs can produce a misleading impression of cost performance unless the benchmarking takes account of the interrelation. For example, a company with ostensibly high distribution maintenance expenses may have unusually old facilities.
- New data may be required on costs and business conditions. For example, station OM&A expenses depend upon substation capacity and station age. These conditions might not be important enough to warrant the gathering of data in a total cost benchmarking study.

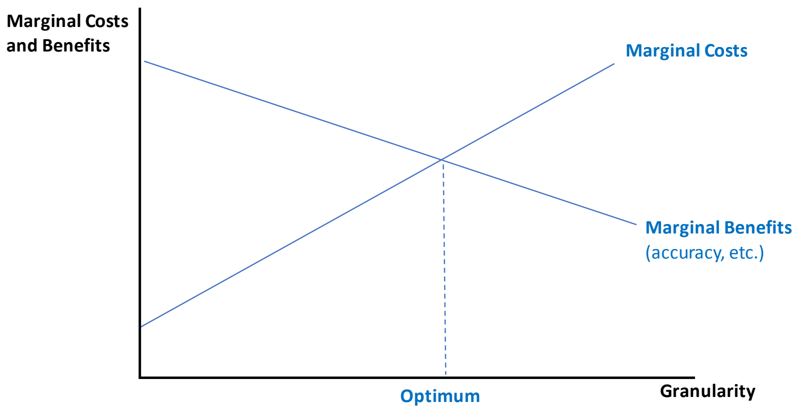
To demonstrate the challenge of increasing granularity, PEG constructed a cost variability metric. We began by calculating the mean and standard deviation of each RRR OM&A account for the Ontario distributors for which we had good data. For each account, we calculated a variability ratio by dividing the standard deviation by the mean to determine the spread of the data. A higher ratio represents an account that has reported expenditures that tend to be further away from the mean.

We found that the average variability ratio at the most granular cost account level was 2.5 times the mean.[3] Our variability metric falls to 1.2 when OM&A accounts are considered at the detailed group level (e.g., Lines, Connections, etc.). The metric falls to 0.6 and 0.4 times the mean when moving from detailed groups to OM&A sub-categories and total OM&A, respectively.

The optimal level of granularity is likely short of the maximum granularity at which data are available. These principles are illustrated in Figure 1 below.

Figure 1

Optimal Granularity of Benchmarking



[3] This level of variability implies that a typical confidence interval constructed around the mean would contain the value of zero cost.

3. APB Precedents

To move from discussion of APB in the abstract to consideration of APB capability for Ontario electricity distributors, it will be useful to consider next the well-established APB programs in Australia and Great Britain. For each jurisdiction, we provide an overview of distributor regulation before discussing the benchmarking in some depth. Additional details of these APB activities are found in the Appendix.

3.1 Australia

Electricity distribution services are currently provided in Australia's National Energy Market by 14 LDCs called distribution network service providers.[4,5] Distribution services are regulated by the Australian Energy Regulator ("AER"). The regulatory system for these distributors is similar to Custom IR in Ontario, featuring multi-year rate plans with revenue caps that are escalated on the basis of index research (for O&M expenses) and forecasts (for capital costs). The AER makes extensive use of cost benchmarking in electricity distribution regulation and also benchmarks electricity transmission cost.

The AER, like the OEB, regulates numerous distributors and makes extensive use of statistical cost research. They use terminology in their ratemaking and statistical cost research that is similar to the OEB's. The AER's benchmarking practices therefore merit close attention by the OEB.[6]

AER benchmarking chiefly focusses on OM&A and capital expenditures and not on capital cost (depreciation, return on rate base, etc.) or total cost. A major reason for this is that the AER has not yet accumulated enough capital cost data for a monetary approach to capital cost measurement like that which the OEB uses to be very accurate. The national regulatory framework did not begin until 2008, and standardized data collection did not begin for more than 5 years thereafter.

In its "Better Regulation" initiative that developed a new approach to expenditure assessment with expanded use of benchmarking, the AER first released an issues paper and then invited written submissions and held many workshops and some bilateral meetings. Once the AER chose a new

---

[4] Australia's National Energy Market excludes electricity distributors in Western Australia.

[5] Many customer services are provided in Australia by independent firms.

[6] The AER, similarly, should and has for some time monitored OEB regulation.

benchmarking regime it issued several Regulatory Information Notices ("RINs"), a detailed *Expenditure Forecast Assessment Guideline*, and an accompanying *Explanatory Statement.*

The AER has "economic" and "category" benchmarking programs. Each has its own RIN. The AER also uses trend analyses and detailed engineering analyses.

3.1.1 Economic Benchmarking

Economic benchmarking appraises the efficiency of more aggregated costs using complicated "top down" statistical methods. Econometric cost functions are used to benchmark OM&A expenses. In contrast to the OEB's current total cost econometric benchmarking program, models are updated annually and multiple model estimation procedures are used.

The AER also computes OM&A productivity indexes. These indexes feature sophisticated multidimensional output indexes with cost elasticity weights drawn from the econometric work.[7] Some simple unit cost metrics using aggregated costs (e.g., total cost per customer) are also computed.[8]

The AER is required to publish an economic benchmarking report annually. They have also published annual reports of their outside consultants, who present results of their research and changes in their methods.

In its IRM decisions, the AER used economic benchmarking to help determine the efficiency of distributors' opex in the base year, the historical year upon which the distributors' revenue requirements were based. The AER also reviewed unit cost metrics (notably average annual operating expenses per customer, capex per customer, and rate base per customer), but preferred an econometric model for the assessment of opex. Other metrics were used as a check on the preferred model, and additional adjustments were made for some special local conditions that distributors faced. Opex revenue requirements were then escalated for the years of the IRM using a "base, step, trend" methodology.

The Australian sample for economic benchmarking of electricity distribution cost now consists of

---

[7] The AER computes *multifactor* productivity indexes as well but these use crude physical asset measures of capital quantities (e.g., line km), a practice the OEB has rejected in past proceedings.

[8] Somewhat confusingly, it calls this "aggregated category" benchmarking when it could more logically be described as aggregated unit cost benchmarking.

data for 14 LDCs for the 2006-2017 period.[9] To bolster the sample for its econometric opex research, the AER's consultant has supplemented these data with data from New Zealand and Ontario LDCs.

3.1.2 Category Analysis

The AER uses the term "category analysis" to mean analysis at the "disaggregated activity or expenditure level." An example is vegetation management. Capex and opex are both addressed. The AER uses the granular cost data gathered for both benchmarking and trend studies. Cost categories considered and benchmarking methods used are summarized in the Appendix.

Category analysis has been chiefly used by the AER to cross check and substantiate results of econometric opex benchmarking. If an LDC is a poor overall cost performer, granular cost performances should also be poor in some areas. However, the AER sometimes relies on the results of the category analysis to set new budgets for the distributor. This is the case particularly for augmentation ("growth-related") and replacement capex. Category benchmarking and trend analysis are used chiefly as screening tools for other types of analysis (e.g., detailed engineering review). The AER states that

> It is neither feasible nor desirable for the regulator to make finding at the granular level about the manner in which a service provider should operate. It is for the service provider's management to decide how best to operate its network with the opex that we determine reasonably reflects the opex criteria.[10]

The initial collection of 2013 data was supplemented by data for the four prior years (2009-2012). The dataset currently contains data from the 2009-2017 period.

<u>Capex Category Analysis</u>

Itemization The category benchmarking RIN requires itemization of capex into various categories. Capex is also itemized with respect to the primary driver of the need for capex. There are four main driver categories.

Demand-Driven Capex

- Augmentation (aka reinforcement) expenditure ("augex")

---

[9] The AER believed that a 10-year initial data series would be optimal but was persuaded to not pursue it due to the concerns of the utilities that the effort to gather or estimate data for the 2 additional years would be significant. Utilities were not permitted to submit estimated data after 2014, except for certain variables that were determined to inherently require estimation.

[10] AER Final Decision, Ausgrid determination 2015-16 to 2018-19 Attachment 7 - Operating Expenditure, April 2015, p. 7-147.

- o Customer-initiated services

Other Capex

- o Replacement expenditure ("repex")
- o Non-network expenditures (e.g., SCADA and buildings)

Appraisals of some kinds of capex can be usefully decomposed into appraisals of how many plant additions are needed and the cost incurred per addition (e.g., cost per motor vehicle). Thus, for key expenditure works categories, the AER gathers data on the number (aka the "volume") of additions as well as their cost.

Augex Analysis Augex is capex required to increase the capacity/capability of the network to maintain performance when demand increases. Typical augex projects include the following:

- Replacement of existing assets with higher-capacity assets (e.g., upgrading existing lines)
- Adding assets (e.g., new lines and substations).

Augex is typically needed when utilization of assets approaches their capacity. These are projects where non-network alternatives ("NWAs") such as demand management are sometimes cheaper. Reported augex is subject to a materiality threshold.

The AER retained Nuttall Consulting to develop a model for benchmarking system augex which was discussed in a 2013 handbook.[11] This model uses information on system capacity (e.g., thermal rating under normal conditions), capacity utilization, forecasted capacity utilization growth, capacity utilization thresholds, and augex cost/volume metrics to produce augex forecasts. Eleven kinds of substation and line assets are separately considered (e.g., zone substations and short rural HV Feeders).

The augex model is used chiefly as a screening tool for identifying categories of expenditure that should be subject to more detailed examination.

> Where the reviewer is satisfied that the NSP is operating at a point close to industry norms then it is more likely that the associated capital expenditure is justified. Where departures from the norms are determined then the reviewer should initiate further technical investigation to establish the reasons for the departures.[12]

[11] AER *Augmentation Model Handbook*, November 2013.

[12] Ibid., p. 9.

The AER also notes that

> The augex model is not a substitute for the detailed project planning processes undertaken by an NSP. The primary roles of the model are to develop an awareness of the cost centres within a network and to facilitate comparisons of similar activities by different businesses. This will promote understanding of the consequences of different technology choices and work practices. It will also help to inform understanding of the impact of geographical and operating environment differences.[13]

Repex The AER defines repex as the "non-demand-driven replacement of an asset with its modern-equivalent, where the timing of the need can be directly or implicitly linked to the age of the asset."[14] Pure repex would maintain a similar service level. Repex typically accounts for 30-60% of an Australian LDC's network capex.

A repex model was developed by Nuttall Consulting to appraise LDC repex proposals. A repex model handbook was issued in 2013.[15] This handbook explains that 15 major kinds of network assets were separately considered, with numerous subcategories. For each asset group, data on system age, the mean and standard deviation of replacement life, and cost/volume metrics for replacements are used to calculate required repex and repex volumes.

Opex Category Analysis

Overview The category RIN requires itemization of opex into categories that are broadly similar to those used in Ontario. The chief benchmarking method used in the AER's opex category analysis is unit cost comparisons. Metrics control for the largest single source of differences in utility cost and are easy for all parties to understand. In addition to cost per unit of operating scale (e.g., cost per mile of line owned), costs of some activities can be usefully decomposed into the volume of activity and the cost per unit of volume. For example, the cost of vegetation management is the product of miles of line cleared and the cost/km of line clearance.

The AER's unit cost and cost/volume metrics have generally featured simple unidimensional scale variables (e.g., total overhead expenses per customer). Extensive effort is not made to develop peer groups. However, the AER sometimes considers how unit costs vary with respect to an additional business condition (e.g., how cost per customer varies with customer density).

---

[13] Ibid, p. 27.

[14] *Electricity Network Service Providers Replacement Expenditure Model Handbook*, November 2013, p. 7.

[15] Ibid.

Maintenance Network maintenance is a major focus of the AER's opex category analysis. These expenses must be itemized into the following categories.

(Non-Emergency) Maintenance by asset type

Routine

Non-routine

Separation of recurrent from non-recurrent expenditures facilitates accurate trend analysis as well as benchmarking. However, this itemization is not always easy for LDCs. For example, some tasks involve both routine and non-routine maintenance.

Routine maintenance expenses can be usefully decomposed into the number of jobs undertaken (e.g., number of poles inspected or maintained) and the unit cost of a job (e.g., inspection cost per pole inspected). Data are thus gathered on the volume of many maintenance jobs.

3.2 Great Britain

Electric power distributor services in Great Britain are currently provided by fourteen LDCs called distribution network operators. Terms of services offered by these companies are regulated by Ofgem. These LDCs operate under an approach to IR called RIIO which currently features revenue caps and eight-year terms. The revenue caps are based on total cost forecasts adjusted for inflation.

Ofgem has traditionally relied on benchmarking as an important tool to assess utility cost forecasts. Aggregated and granular benchmarking are conducted. The final revenue requirements for distributors in the first round of RIIO were based 75% on Ofgem's view and 25% on the utility's proposal.

Ofgem's benchmarking has focussed on total operating and capital expenditures (aka total expenditures or "totex"). One reason is that Ofgem, like the AER, has not gathered the many years of data for the monetary approach to capital cost and quantity measurement to be very accurate. A second reason for the focus on totex was Ofgem's decision to change their capitalization policies to allow distributors to capitalize a percentage of their *total* expenditures ("totex") rather than all capex and a small portion of opex.

In the most recent round of electricity distribution IRM proceedings, called RIIO-ED1, Ofgem used both aggregated and granular benchmarking. Ofgem leaned heavily on an APB assessment, which it called the "disaggregated model." In addition, two top down econometric totex benchmarking models were developed. One of these models featured an explanatory variable consisting of the weighted average of the value of assets and the number of customers served. The other model featured an explanatory variable consisting of a weighted average of explanatory variables from the disaggregated benchmarking.

British regulation is an iterative process with the distributors allowed to change their cost proposals and get feedback from the regulator several times prior to Ofgem's final decision. Ofgem's methodology could change based on new information during the proceeding. We focus below on the methodologies Ofgem utilized to make its final decisions on the disaggregated model. Four distributors had forecasts that Ofgem deemed to be sufficiently justified and as a result, their revenue requirements were set in advance of the final decision.

Ofgem's dataset was limited to actual data for most years of the previous 5-year price control period and the 8-year cost forecast that each distributor proposed.[16] Reliance on forecasted cost data in benchmarking is unusual. There was thus a maximum of 13 observations per distributor or 182 total potential observations. The data were collected as part of the business plan filings. The forecasted data were refined with each filing of the business plan (e.g., prior to the draft decision and prior to the final decision). Despite the small size of the British data sample, Ofgem did not supplement the data it collects with data on overseas electricity distributors. The small size of the dataset severely limited the quality of econometric models that could be developed.

The resultant dataset included cost data similar to that filed by Ontario LDCs on the RRR, as well as data on asset health and volume of work data (e.g., number of highway relocations expected and number of assets replaced) which permit calculation of cost/volume metrics for work performed. The asset health data feature probability assessments of asset failures itemized by asset types (e.g., switchgear) and the distributor's assessment of each asset's health. LDCs assigned all of their network assets to one of five categories ranging from new to end of serviceable life and one of four measures of how critical the asset is to the function of the network, ranging from low to very high.

The disaggregated model assessed most of the cost proposals presented by LDCs grouped into 5 specific cost areas: network operating costs; load-related capex; asset replacement, refurbishment, and civil works capex; non-core, non-load-related capex; and closely associated indirects, business support,

---

[16] At least one year of data from the previous price control period was forecasted.

and non-operational capex (e.g., non-network capex such as vehicles and small tools and equipment). These cost areas were further broken into numerous cost subcategories.

Various techniques were used to conduct the disaggregated cost assessments. These techniques included unit cost comparisons, cost/volume comparisons, econometric cost modelling, trend assessments of distributor costs (e.g., trends in unit costs and quantities of work performed, and costs), and engineering assessments.[17] Outside consultants were retained for some of these tasks.

In the most recent round of IRM updates, Ofgem's review of distributors' proposed repex and augex has, for various asset categories, divided these types of capex into volumes of work and the unit cost of that work. Cost/volume ratios for most categories of repex and augex were appraised using "median unit cost analysis". This took the form of setting the benchmark unit cost at the median value for the industry during the historical period, forecast period, or the entire time series depending on the subcategory. For repex, this was supplemented by a qualitative review undertaken by an engineering consultant.

Repex *volumes* were appraised in one of three ways: an age-based survivor model, run-rate analysis, or a qualitative assessment. Assets with a reliable age profile were assessed using the age-based survivor model. This model estimated the number of specific kinds of assets (e.g., 33 kV poles) requiring replacement during the upcoming IR plan based on the age of the distributor's current assets and the age of assets at the time of replacement in the prior IR plan. This model assumed that the service lives of assets will either remain the same or improve due to better asset management practices. A normal distribution for the cumulative probability of asset failure was also assumed.

Assets without reliable age profiles were subject to a run-rate analysis that took the form of replacement rates based on data submitted on disposal volumes as a proportion of distributor assets in service. An industry median value for this metric was calculated and used as the baseline for all distributors. This was supplemented by qualitative analysis.

Augex volumes were appraised using qualitative and ratio analyses with the specific appraisal method varying between augex categories. Ratio analysis of augex categories compared the distributor's proposed volumes of work to industry medians. For one subcategory of augex the median

[17] We do not consider engineering assessments to be in the scope of benchmarking and therefore, do not discuss them in greater detail.

value for the subcategory was calculated and used as the baseline, but changes were allowed to reflect various distributor characteristics.

Three granular cost categories were assessed using simple econometric models: closely associated indirect expenses (e.g., stores and call center), tree cutting to address specific tree trimming and vegetation management standards, and trouble calls due to overhead faults. With respect to closely associated indirect costs, the costs of eight subcategories of closely associated indirect costs were summed together for each distributor for each of the eight forecast years. Ofgem chose not to use the historical data for these cost categories due to sharp cost declines that occurred during the previous price control, reducing the sample for model estimation to only 112 observations.[18] The cost model had only two explanatory variables.[19] Four other subcategories of closely associated indirect costs were assessed using different techniques. The econometric models for tree cutting and trouble calls due to overhead faults also included few explanatory variables. The model for trouble calls due to overhead faults only featured 1 explanatory variable.

The granular costs calculated from the various disaggregated benchmarking assessments were summed together to present an assessment of the efficient level of *total* expenditures for each distributor. A final view of efficient totex was then calculated by summing together the modeled total expenditures from the disaggregated benchmarking with the totex resulting from the econometric models with a 50% weight on the disaggregated model and 25% weights on each of the econometric totex models.[20] The resultant efficient totex target reflected an upper quartile performance standard. This value was then adjusted to add in the cost categories excluded from the benchmarking and undo data normalizations to arrive at Ofgem's final estimate of totex for each distributor.

[18] The samples for model estimation for tree cutting and trouble calls due to overhead faults were even smaller, with 104 and 52 observations, respectively.

[19] These variables were the natural log of scale (as based on asset value) and assets installed in prior year.

[20] Ofgem used different weights for its initial assessment with a 75% weight on the disaggregated model and 12.5% weights on each totex model.

4. Benchmarking Methods

In this section of the report we consider three statistical research tools that can be used to benchmark granular costs: unit cost metrics, econometrics, and data envelopment analysis. We start with a review of pertinent cost theory.

4.1 Cost Drivers and Cost Functions

In comparing costs that utilities incur, it is widely recognized that differences in their costs depend in large measure on differences in business conditions that they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves given the external business conditions that it faces. Benchmarks should therefore properly reflect these conditions.

Economic theory can help identify cost drivers and control for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to variables representing business conditions in its service territory. When the focus of benchmarking is *total* cost, relevant business conditions theoretically include the prices of capital and OM&A inputs and the operating scale of the company. Miscellaneous other business conditions may also drive cost. In electricity distribution these conditions include the extent of forestation in the service territory.

Restricted (aka short-run) cost functions are useful when the focus of benchmarking is a granular cost. Relevant business conditions driving each granular cost include prices of inputs in that subset of costs and the quantities of *other* inputs that the utility uses. When benchmarking total OM&A expenses, for example, prices of OM&A inputs and the quantities of capital used by the company are cost drivers.[21]

The presence of capital quantity variables in OM&A cost functions means that appraisals of OM&A expenses should consider attributes of capital inputs that distributors own. For example, it is generally more costly to operate and maintain capital facilities the larger is their capacity. A utility that has newer facilities may tend to have lower OM&A expenses than a distributor with older facilities.

Another reason quantities of other inputs matter in a granular cost benchmarking study is that

[21] For costs of operating and maintaining substations, prices of substation O&M inputs and the quantity of substations matter.

some of the other inputs may be substitutes. For example, a utility may, by employing extensive outside services, contain its expenses for executives and middle management.

Regardless of the category of cost that is benchmarked, economic theory allows for multiple scale variables in cost functions. This is useful since multiple dimensions of scale often affect utility cost. For example, the capital cost of an electricity distributor depends on the number of customers it serves as well as on its expected peak load and the geographic dispersion of its customers.

Capital *expenditure* can also be addressed by cost theory. Capex depends on the prices of labor, materials, and equipment that are needed to make plant additions. It also depends on the general operating scale of the company, the extent to which demand growth strains capacity, and on the share of assets that are close to replacement age.

4.2 Benchmarking Methods

4.2.1 Unit Cost Research

<u>Index Basics</u>

Benchmarking research using unit cost metrics is a form of index research. An index is defined in one popular dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[22] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to corresponding values for a sample of utilities. Companies for which sample data are drawn for such an exercise are sometimes called a peer group.

<u>Unit Cost Indexes</u>

A simple comparison of costs of utilities may reveal little about their cost performances if there are large differences in the cost drivers that they face. In index-based cost benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities is typically the greatest source of variation in their costs. It makes sense then to use as metrics ratios of cost to measures of operating scale. Such a ratio is sometimes described as the cost *per unit* of operating scale or "unit cost." In comparing the unit cost of a utility to the average

[22] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

for a peer group, an automatic (if imperfect) control is introduced for differences in the operating scale of the companies. This permits inclusion of companies with more varied operating scales in the peer group.

The unit cost of a company is typically compared to the values of other companies. Most commonly, the comparison is to the peer group mean. However, it is straightforward to compute the difference between a distributor's unit cost and a unit cost that is commensurate with a top quartile or frontier performance.

A unit cost *index* is the ratio of a cost index ("*Cost*") to a scale index ("*Scale*").

$$Unit\ Cost = Cost/Scale. \qquad [1]$$

Each component index compares the value of the metric to the average for a peer group. The scale index can be multidimensional if it is desirable and practical to measure operating scale using multiple scale variables.[23] Each dimension of scale that is itemized is measured by a subindex. The scale index then summarizes the scale of operation by taking an average of the scale comparisons.

The design of the scale index is important. In cost performance research, it makes sense for the scale index to reflect the impact of scale on *cost.* In that case, the scale index should address dimensions of the workload that drive cost. The weights for scale variables should reflect the relative cost impacts of these drivers. Peak demand, line length, and the number of customers served are widely recognized to be scale-related drivers of energy distributor cost.

The sensitivity of cost to a change in the magnitude of a business condition variable is commonly measured by its cost "elasticity." The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number. It is straightforward to estimate elasticities like these using econometric estimates of cost model parameters. The weight for each variable in the scale index can then be its share in the sum of the estimated cost elasticities of the model's scale variables. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant scale-related cost driver.

---

[23] A unit cost index for Northern Power, for instance, would in year *t* have the general form:

$Unit\ Cost_t^{Northern} = \frac{Cost_t^{Northern}/Cost_t^{Peers}}{\sum_i w_i \frac{Scale_{t,i}^{Northern}}{Scale_{t,i}^{Peers}}}$. Here w_i is the weight assigned to each scale variable *i* and $\sum_i w_i = 1$.

We noted in Section 4.1 that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. Unit cost indexes do not automatically control for differences in these other cost drivers between utilities. The accuracy of unit cost benchmarking therefore depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility. Custom peer groups will sometimes materially improve benchmarking accuracy. Different unit cost peer groups may be appropriate for different utilities and for different costs of the same utility. For example, a peer group for a utility's distribution expenses might ideally face similar amounts of forestation whereas a peer group for billing and collection expenses likely would not.

Cost/Volume Metrics

An expenditure can be decomposed into the "volume" of work and the cost per unit of volume.

Cost = Volume of work x (*cost/volume*) [2]

For example, capex to replace distribution poles is the product of the number of poles replaced and the capex per pole replaced. The cost per unit of volume is a unit cost but is not a comprehensive measure of performance like the unit costs discussed above. The volume of activity in [2] is of equal or greater importance and may also merit benchmarking. These volumes depend in a complicated way on various business conditions that include the general operating scale of the utility and its short-term need for this kind of work.

It should also be noted that capex/volume metrics can vary greatly with the specific kind of asset. For example, capex per pole replaced is very sensitive to the kind of pole replaced (e.g., concrete vs. steel. vs. wood). Capex/volume metrics are therefore more useful to the extent that they are itemized by asset type.

Productivity Indexes

The Basic Idea A productivity index is the ratio of a scale index to an input quantity index ("*Inputs*"):

$$\textit{Productivity} = \frac{\textit{Scale}}{\textit{Inputs}} . \qquad [3]$$

It measures the efficiency with which firms achieve their scale of operation.

It can be shown that cost is the product of a properly-designed input price index ("*Input Prices*") and input quantity index:

$$Cost = Input\ Prices \bullet Inputs. \quad [4]$$

Relations [1], [3], and [4] imply that

$$Unit\ Cost^{Real} = \frac{Cost/Input\ Prices}{Scale} = \frac{Inputs}{Scale} = 1/Productivity. \quad [5]$$

Thus, an input price-adjusted (aka "real") unit cost index will yield the same benchmark ranking as the corresponding productivity index. A company with low real unit cost has proportionately high productivity.

Productivity indexes can be designed to appraise productivity levels or trends. *Multilateral* productivity indexes are designed to measure both. *Bilateral* productivity indexes compare only levels, while productivity *trend* indexes measure only trends.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. Some indexes measure productivity in use of a subset of all inputs such as labor, all OM&A inputs, or capital. These are sometimes called partial factor productivity ("PFP") indexes. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple (e.g., capital, labor, material, and service) inputs. These are sometimes called *total* factor productivity ("TFP") indexes even when they exclude important inputs such as energy that utilities use. The OEB periodically measures the trend in the TFP of Ontario electricity distributors because it is germane in the choice of X factors for their rate and revenue cap indexes.

Productivity indexes, like unit cost indexes, do not automatically control for differences in all cost drivers that vary between utilities. We noted above that cost depends on miscellaneous other business conditions in addition to input prices and operating scale. The accuracy of productivity benchmarking therefore depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility. It can be challenging to choose a peer group that is appropriate for benchmarking productivity. Different productivity peer groups may be needed for different utilities and for different costs of the same utility.

4.2.2 Econometric Modeling

The Basic Idea

The relationship between the cost utilities incur and variables that measure the business conditions they face (sometimes called the "structure" of cost) can be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating parameters of models of relationships between economic variables using historical data on the variables.[24] Parameters of utility cost functions can be estimated using historical data on costs incurred by utilities and business conditions that they faced.

A cost function fitted with econometric parameter estimates is called an econometric cost model. We can use such models to predict a utility's costs given local values for the business condition variables. These predictions are econometric benchmarks. Cost performance in year *t* is measured by comparing a company's cost in that year to the cost projected for that year by the econometric model. *Historical* costs can be appraised given historical data on business conditions. Forecasted or proposed *future* costs can be appraised using forecasts of future business conditions.

Suppose, for example, that we wish to benchmark the distribution O&M expenses of Northern Power. We might then predict the cost of Northern in period *t* using the following simple model:

$$ln\widehat{COM}_{Northern,t} = \hat{a}_0 + \hat{a}_1 lnN_{Northern,t} + \hat{a}_2 lnL_{Northern,t} + \hat{a}_3 lnU_{Northern,t}.$$

Here $\widehat{COM}_{Northern,t}$ denotes the predicted cost of the company, $N_{Northern,t}$ is the number of customers it serves, $L_{Northern,t}$ is the length of its lines and $U_{Northern,t}$ is the share of undergrounded facilities in distribution gross plant value. The $\hat{a}_0$, $\hat{a}_1$, $\hat{a}_2, and\ \hat{a}_3$ terms are econometric estimates of model parameters. Performance might then be measured using a formula like

$$Performance = \ln\left(\frac{COM_{Northern,t}}{\widehat{COM}_{Northern,t}}\right)$$

where ln is the natural logarithm of the ratio in the parentheses.

Stochastic Considerations

Econometric research involves certain critical assumptions. One of these assumptions is that the value of an economic variable (sometimes called the dependent or left-hand side variable) is a function of certain other variables (sometimes called explanatory or right-hand side variables) and an error term. Returning to our example, the assumption concerning the OM&A expenses of each firm *h* in the sample might be that in each year *t*

$$lnCOM_{h,t} = a_0 + a_1 lnN_{h,t} + a_2 lnL_{h,t} + a_3 lnU_{h,t} + error_{h,t}.$$

The error term in an econometric cost model is the difference between actual cost and the cost

[24] Econometric estimation of model parameters is sometimes called regression.

predicted by the model. This term is a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. Reasons for cost model errors include mismeasurement of costs and business conditions, exclusion from the model of relevant business conditions, and failure of the model to capture the true shape (aka form) of the cost structure.

It is customary to assume that error terms in econometric models are random variables drawn from probability distributions with measurable parameters. One benefit of this approach is that statistical theory can then be used to appraise the importance of various business condition variables as cost drivers. Tests can be constructed for the hypothesis that the parameter for a cost driver variable included in a model equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Statistical theory also provides useful guidance on the accuracy of econometric cost benchmarks. One important result is that an econometric model can yield biased predictions if relevant business condition variables are excluded from the cost model. A model used to benchmark the cost of an electricity distributor serving a rural area might, for example, yield biased cost predictions if it excludes appropriate measures of ruralness. It is therefore desirable to include in a cost model all cost drivers for which data are available at reasonable cost, are believed to be relevant, and which have plausible and statistically significant parameter estimates.

Statistical theory also provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the data at a given level of confidence. It can be shown that confidence intervals are wider, reducing benchmarking precision, to the extent that:

- the model is less successful in explaining variation in costs in the sample;
- the size of the sample is smaller;
- the number of business condition variables included in the model is larger;
- the business conditions of sample companies are less varied; and
- the business conditions of the subject utility are less similar to sample norms.

These results also have implications for benchmarking. For example, they suggest that the precision of an econometric benchmarking model can often be improved by pooling data for a large sample of companies over multiple years. Another implication is that the precision of econometric benchmarking is actually *enhanced* by using data from companies with diverse operating conditions. For example, to capture the impact of variables that measure the ruralization of a service territory it is useful to have data for utilities that operate under urban as well as rural conditions.

Confidence intervals developed from econometric results also permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average efficiency standard and compute the confidence interval for the benchmark that corresponds to the 90% confidence level. It is then possible to test the hypothesis that the company has attained the benchmark standard of efficiency. If, for example, the company's actual cost exceeds the best guess benchmark generated by the model but nonetheless lies within the confidence interval this hypothesis cannot be rejected. In other words, the company is not a *significantly* inferior cost performer. Suppose, alternatively, that the company's cost is above the cost predicted by the model by enough to be outside the confidence interval. We may then conclude that it is a *significantly inferior* cost performer.

Model Estimation Procedures

Various parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software packages such as R. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. PEG typically uses a GLS estimator that corrects for autocorrelation and groupwise heteroskedasticity in the error terms. These are common phenomena in statistical cost research. When least squares procedures are used to estimate model parameters, cost benchmarks generated from fitted econometric models reflect an average performance standard.

Stochastic frontier analysis ("SFA") is an alternative way of using econometrics to benchmark costs. Like least squares analysis, SFA involves specification of a function that relates cost to scale metrics, input prices, and other business condition variables. SFA is focused on estimating the parameters of the minimum cost function as well as an inefficiency factor for each firm as opposed to estimating the relationship between expected, or average, cost and business conditions.

Data Envelopment Analysis

Data envelopment analysis ("DEA") is a very different approach to performance measurement.

It often does not involve estimation of function parameters and is therefore described as "non-parametric." Instead, linear programming is used to "envelop" data on the outputs and inputs of a sample of firms. DEA is essentially a technique for identifying what are known in economics as isoquant or isocost curves and for measuring the distance of individual firms from the efficient cost (production) frontier reflected in that isocost (isoquant).

In a basic input-oriented DEA model, the relative efficiency of a firm is determined by assigning weights to inputs and outputs such that the ratio of aggregated outputs to aggregated inputs is maximized. This linear programming problem is subject to the constraint that the efficiency score cannot exceed a value of one for a firm using the same set of weights. The result of this process is an efficiency measure for each firm that takes a value between zero and one. These efficiency scores are relative to those of "peers" identified through the analysis and which set the efficiency "frontier." The DEA efficiency score has the intuitive interpretation that, relative to the peers, it measures the amount by which a firm can contract all of its inputs and still produce the same level of output.

4.3 Capital Cost Issues

In utility cost accounting the main components of the annual cost of capital are depreciation expenses, return on investment, and taxes. Since electricity distribution is capital-intensive, capital cost containment matters and methods for measuring capital costs, prices, and quantities play important roles in statistical research on total cost (as well as capital cost) performance.

Monetary approaches to measuring these variables have typically been used in North American cost research. This general treatment of capital cost has a solid basis in economic theory and is widely used in governmental and scholarly empirical research. Monetary approaches decompose capital cost into consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \times Quantity^{Capital}. \qquad [6]$$

The capital quantity index is calculated by deflating reported values of capital assets.[25]

Some monetary methods value assets in historical dollars whereas others use current (aka

[25] The capital *price* index reflects the cost of owning a unit of capital. It is sometimes called a rental or service price since, in competitive markets, prices of asset rentals tend to reflect the unit cost of capital ownership. Capital cost depends on prices of assets (often proxied by construction costs) and market rates of return on capital. Capital price indexes should reflect both of these prices.

replacement) dollars. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires the netting off of implicit capital gains when asset prices (or construction costs) rise. Another issue in measuring capital quantities (and prices) is the assumed patterns of depreciation and decay.

Utilities have diverse methods for calculating depreciation expenses. In calculating capital costs and quantities using monetary methods, it is therefore desirable to rely on the utilities chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. For earlier years the desired gross plant addition data are frequently unavailable. It is then customary to use the value of all plant at the end of the limited-data period to estimate the quantity of capital it reflects using construction price indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is called the "benchmark year" of the capital quantity index.

Since, additionally, the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital cost and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible. Where numerous years of capital data are unavailable, benchmarking therefore typically focuses on capital *expenditures*, usually proxied by the value of gross plant additions, rather than capital cost.[26]

4.4 Performance Standards

Cost benchmarks based on statistical research often reflect statistical performance standards. Alternative performance standards include the mean performance and frontier performance. It is useful to know how much a distributor's cost performance falls short of the best possible performance. However, the best performance scores in statistical cost benchmarking studies often reflect deferred expenditures, one-time events, or inadequacies in benchmarking methods rather than the minimum *sustainable* cost of service provision. A workable alternative to a frontier standard is top quartile performance.

[26] In this paper, we use the terms capex and gross plant additions interchangeably.

4.5 Cost Exclusions

Costs are excluded from benchmarking studies for various reasons. They may not be subject to a regulator's jurisdiction or may be addressed by deferral and variance accounts in IRMs. Costs may also be excluded because they are unusually difficult to benchmark. For example, pension expenses are often excluded from benchmarking studies because they are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses in econometric cost research is the lack of federal labor price indexes that encompass them. Other costs that are often excluded from benchmarking studies include those for energy procurement, bad debt, franchise fees, conservation programs, and demand management.

5. Data Considerations in Ontario APB

Accurate statistical performance research is facilitated by abundant, high quality data. In this section we consider sources of data currently available for statistical benchmarking of granular Ontario electricity distributor costs. Strengths and weakness of the data are identified, and implications are discussed for the development of an appropriate APB framework.

5.1 Ontario Data

Around sixty-five electricity distributors operate in Ontario today. In addition to distribution services, these LDCs provide extensive customer services that include metering, billing and collection, and conservation and demand management ("CDM"). The largest LDC, Hydro One Networks ("HON"), also provides most electricity transmission services in Ontario. Ontario electricity distributors do not generate electricity or deliver natural gas. Thus, administrative and general ("A&G") costs that most Ontario distributors report are chiefly incurred in the provision of electricity distributor services.

5.1.1 RRR Data

The primary source of standardized data on the cost and operating scale of Ontario LDCs is the Reporting and Record Keeping Requirements ("RRR") reports to the OEB. The cost data must conform to a Uniform System of Accounts ("USoA"). Each Ontario electricity distributor has been required to file these reports annually since 2002. An extensive discussion of the USoA which facilitates standard itemization is included in the *Accounting Procedures Handbook for Electricity Distributors* ("APH"). To provide data quality assurance, the OEB has since 2015 required that both quarterly and annual RRR filings be certified by an executive signing officer of the company. Tables detailing data that have been gathered using RRR are provided in the Appendix.

5.1.2 Rebasing and Planning Data

Distributors in Ontario are required to file periodic rate applications that rebase their rates to the cost of service that they incur. The OEB's principal use of APB is expected to be in the processing of these applications. Distributors are also required to file consolidated distribution system plans ("DSPs") at each rebasing or every five years, whichever is more frequent. In devising an APB framework it is important to examine how cost data are presented in these submissions. Review of these data is also worthwhile because some could be useful in benchmarking.

The OEB's guidelines for distributor rate applications and DSPs are set out in Chapters 2 and 5 of its *Filing Requirements for Electricity Distribution Rate Applications* and various appendices. The most recent edition of these *Filing Requirements* was released in July 2018. These requirements are the minimum level of information a distributor should provide in its rate filings. A wide variety of data must be reported for several historical years, the bridge (current) year, and the prospective test year. The OEB has developed data templates to assist distributors in their reporting. As the accounting standards changed for many distributors in recent years, distributors are also required to identify the accounting standard that was used in each year reported. Rate filings must be accompanied by a certification by a senior officer of the distributor that the evidence filed is accurate, consistent and complete to the best of their knowledge.

Distributors are asked to itemize their OM&A expenditures in rebasing applications at multiple levels of granularity. They must decompose their total recoverable OM&A expenses into five "major categories": distribution operation, distribution maintenance, (total) billing and collecting, (total) community relations, and (total) administrative and general expenses.[27] Distributors are also asked to provide further detail on certain OM&A programs, but these submissions are not subject to a standard itemization protocol.

Data are also requested in some areas of special interest including accounting standards, employee costs, capitalization of OM&A expenses, reliability and customer service quality, regulatory costs, and charitable and political donations. Requested employee cost data include the number of full-time equivalent employees ("FTEs"), total salaries and wages (including overtime and incentive pay), total benefit costs (current and accrued), and total compensation, all itemized for management (including executive) and non-management (union and non-union) employees. Distributors must also report O&M, administrative, and total OM&A expenses per customer and per FTE.

The *Filing Requirements for Electricity Distribution Rate Applications* also have specific requirements for the filing of capital data in Cost of Service and Distribution System Plan ("DSP") filings. For a cost of service rebasing, a distributor must file a fixed asset continuity schedule showing the opening balance, (gross) plant additions and disposals, and closing plant balance for each year as well as the related accumulated depreciation opening and closing balances, the depreciation expense,

---

[27] Computations are presented in the Appendix.

depreciation disposals, and net book value for each plant account. These plant accounts match the itemization of gross plant value in the RRR.[28] At a minimum, the LDC must provide these data for the earlier of 1) all historic years back to its last rebasing or 2) at least three years of historical actuals, in addition to the Bridge Year and Test Year forecasts.[29] Applicants must also state their typical service life assumptions[30] and the average remaining service lives for detailed asset categories. A DSP typically considers a ten-year period consisting of five historical years (ending in the bridge year) and five forecast years.

The DSP requirements include a request that capex be decomposed into the following four investment categories.

- system service investments
- system access investments
- system renewal investments
- general plant investments

These itemizations are similar to those requested by the AER, but itemization by asset class is not requested. Data must be reported back to 2010 as well as for five forecasted years.

System service investments include those designed to upgrade system capabilities such as increasing the capacity of circuits, conductors, and distribution substations; line extensions and property acquisitions; and projects that address system operational objectives such as SCADA, distribution loss reductions, and automation. System access investments are those that result from statutory, regulatory, or other requirements that distributors provide customers with access to the distribution system. These investments include capex for customer connections, line relocations, and metering. System renewal projects include those designed to replace or refurbish assets nearing the end of their service life. General plant investments include those designed to address non-network needs such as billing systems and software, supplies, structures, and equipment and tools.

---

[28] The asset continuity schedule does not include all the plant accounts reported in the RRR. For example, the street lighting and signal systems listed in the RRR data are not included in the fixed asset continuity schedule.

[29] The template for these schedules is provided in the Appendix.

[30] *Filing Requirements*, Appendix 2-BB Service Life Comparison.

When projects fall into two or more of these four broad categories, the OEB requests that they be placed in the category corresponding to the "trigger" driver.[31] Some distributors use their own method to allocate capex to the various categories rather than the method suggested by the OEB.

Several kinds of data are requested in DSPs that could be useful in benchmarking. These include the following:

- Number and length of circuits by voltage level and the number and capacity of substations
- Age profiles of assets
- Degree to which the capacity of existing system assets is utilized relative to planning criteria

However, data like these which are submitted in DSPs are not standardized. Submissions of larger distributors like Hydro One tend to be much more detailed. The latest DSP requirements also ask that capex, O&M, and total expenditures be reported per customer and per km of line.

Distributors must also report capex for individual projects but there is no standard itemization protocol for these submissions either.[32] A lack of standardization of submitted capex data is apparent. For example, some distributors itemize capex for new installations based on rate class or whether facilities were overhead or underground, while others report no capex for new installations at all.

5.1.3 Canadian Prices

Extensive data on Canadian prices are available from Statistics Canada. These include average weekly and hourly earnings in the utilities sector of Ontario's economy, the gross domestic product implicit price index for final domestic demand, and some useful asset price deflators. Forecasts of several inflation indexes are available from the Conference Board of Canada and large Canadian banks.

5.1.4 Advantages and Idiosyncrasies of Ontario Data for Granular Cost Benchmarking

Our review of available Ontario data prompts us to note the following advantages and disadvantages of these data in the benchmarking of granular distributor costs.

[31] An example of a project which may fit into multiple categories would be a substation replacement that also increases the substation's capacity to address expected load growth.

[32] The reporting template does state that "The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category." *Filing Requirements*, Appendix 2-AA Capital Projects Table.

Advantages

The advantages of Ontario data for APB include the following.[33]

- The OEB has for many years gathered RRR data on OM&A expenses that are itemized by activity.[34] The requested itemization of OM&A expenses is unusually extensive. For example, distribution OM&A expenses must be decomposed into operation and maintenance categories. There are five categories of station operation expenses compared to one on the corresponding form for American utilities. Ontario's USoA provides guidance on appropriate itemizations. Itemization of some costs that are hard to benchmark (e.g., taxes and franchise fees) or not subject to the OEB's jurisdiction (e.g., energy conservation and street lighting expenses) facilitates their exclusion from benchmarking.
- A considerable amount of data have also been gathered on the scale of demand (e.g., peak loads) and the distribution network [e.g., lengths of overhead and underground distribution lines (in circuit miles)] and on some other business conditions that are useful in benchmarking.
- The number of distributors filing data every year is far greater than in many countries (e.g., Australia and Britain). This encourages quick accumulation of sizable samples that can be useful in econometric modelling and other kinds of statistical benchmarking.[35]
- The OEB has the authority to request additional data that would be useful for benchmarking jurisdictional distributors. Options for improving data available from other countries are, in contrast, quite limited.
- There is no need for currency conversions when Ontario data are used to benchmark Ontario distributors. Input prices may differ across the vast province but adjustments for these differences are feasible using publicly available data.

Idiosyncrasies

Ontario operating data also have some idiosyncrasies in distributor cost benchmarking which

[33] Some of these circumstances are also advantages for total cost benchmarking.

[34] Data on gross plant value are itemized by asset type.

[35] This data advantage is especially large over Britain.

affect the design of an APB framework. Here are our primary concerns.

Consistency of Itemizations The consistency of OM&A expense itemizations between Ontario distributors and over time has been uneven for some of the more granular cost categories. Many distributors report zeros for more granular cost categories when zero values are implausible. In 2016, miscellaneous distribution expenses was one of the largest categories of aggregate reported distribution OM&A expenses. Miscellaneous general expenses was one of the largest categories of reported A&G expenses.

Lack of Program and Volume Data Costs of several important programs that may merit benchmarking(e.g., pole replacement, substation refurbishment, and vegetation management) are not currently itemized on the RRR. Neither does the RRR gather standardized volume data for capex or opex programs (e.g. number of poles replaced).

Capital Cost The OEB has never requested RRR itemizations by asset type (e.g., substations) for either gross plant additions or accumulated depreciation. However, stakeholders have indicated that these data are available.

5.1.5 Implications for APB

Let's consider now some implications of these considerations for the design of an APB program for provincial LDCs.

<u>Opex</u>

- Improved itemization of reported OM&A expenses would make granular cost benchmarking more accurate.
- Benchmarking opex at higher levels of aggregation avoids itemization issues.

<u>Capital Cost and Capex</u>

- Additional data are required to benchmark the *itemized* capital cost, capex, or total cost (capital plus OM&A costs) of particular kinds of distributor assets like substations or lines. Stakeholders report that these data are available. Benchmarking is possible immediately for each distributor's *total* capital cost and total capex.[36] However, it would be highly desirable to have more data on system age for such an exercise.

- For the foreseeable future, accurate benchmarking of itemized (e.g., substation) *capex* will be easier than accurate benchmarking of itemized *capital costs* using monetary methods. We have seen that Australian and British regulators do not try to benchmark capital cost using monetary methods at all with the limited data available.

- The working group indicated an interest in adopting cost-volume metrics for certain capital expenditure activities. It also thought analysis of the four categories of capital expenditures (i.e., system service, system renewal, system access, and general) is desirable.

General

- The reporting of better quality data by distributors is an important priority to ensure the effectiveness of APB. Itemizations on RRR submissions need to be more consistent. Itemizations on rate applications need to be more consistent with those on the RRRs. New data on costs and business conditions need to be gathered.

- The OEB currently gathers certain data and not others, and this could influence the additional data that it makes sense to collect. For example, it is not such a large step to gather more systematically, for benchmarking purposes, itemized capex and other data that are already gathered in rebasing proceedings. The OEB may, in general, be able to improve on the APB methodologies used by the AER and Ofgem and should not feel bound by their examples.

5.2 Preliminary Empirical Results

We have undertaken some preliminary research to develop benchmarking methods that support effective APB in Ontario. This research included calculation of unit cost metrics, the development of software to share unit cost results, and some econometric modelling.

5.2.1. Unit Cost Research

Simple cost ratio metrics can provide the basis for the start of an inquiry as to why certain cost

[36] It should be noted, however, that some key variables needed to benchmark capex have not been gathered.

items are different than average. Business conditions such as differing labor prices, age of capital assets, extent of undergrounding and other characteristics discussed elsewhere in this report are not reflected in these metrics. To the extent that these business conditions influence expected cost levels, unit cost measures will be an imperfect measure of cost performance. The basis for a response as to why average cost levels differ should include the impact of company-specific business conditions.[37] Therefore, it is fair to say that simple cost per customer metrics can assist all parties in deciding what questions to ask, but will not necessarily provide answers without additional analysis. The screening function of the metric has value even if it does not account for all business conditions relevant to a full cost performance evaluation.

Table 1 shows the kind of result which software that we have developed can provide for each distributor. This table displays cost per customer ratios for the major categories of OM&A cost. The spreadsheet allows for the expansion of each featured cost grouping to show the account level data used in constructing the cost category. This will allow the user to both validate the calculations and analyze the source of any differences in average cost. Cost per customer metrics are also provided for these more granular account level metrics. In the table presented, the detail for the "other" cost category is shown which includes accounts such as load dispatching.

The table also shows unit cost indexes in addition to the cost per customer metrics. As noted earlier in the report, a unit cost index is able to consolidate multiple scale variables into a single measure of scale that is used as the denominator of the unit cost ratio. In the example, both customers and line length are used as scale measures. Econometric work provided the basis for what weight each scale measure should receive in the calculation of overall scale. Unit cost metrics are not provided for more granular account level detail because there is no econometric work to support the required calculations.

As a visual guide to relative cost performance, different ranges of performance were assigned a short description and given a color code. The +/- 25% cut off points for denoting very good or bad performance were adopted from the total cost benchmarking work for this example. The categories are arbitrary and can be changed without consequence to suit the needs of APB.

[37] Measuring the impact of business conditions could include adjusting cost levels for prevailing local prices, comparing the cost of the distributor to others with similar business conditions, quantifying differences in accounting treatment, or other statistical analysis such as econometrics.

Table 1

Unit Cost Summary Table

Metric Result	Cost Containment
25%+ Below Average	Far Better than Average
0-25% Below Average	Better than Average
0-25% Above Average	High Cost
25%+ Above Average	Very High Cost

			Cost per Customer				Unit Cost Index		
Category	**2016 Cost Level**	**% of Total**	**$/Customer**	**Industry Average**	**Performance***	**Screening Result**	**Industry Average**	**Performance***	**Screening Result**
Meter Expense (including Maintenance)	$1,348,674.74	3.80%	$8.67	$9.93	-13.55%	Better than Average	$14.37	-12.49%	Better than Average
Line Operation and Maintenance	$5,328,431.72	15.01%	$34.27	$46.42	-30.35%	Far Better than Average	$63.11	-29.65%	Far Better than Average
Maintenance of Poles, Towers and Fixtures	$457,043.89	1.29%	$2.94	$4.83	-49.64%	Far Better than Average			
Operation Supervision and Engineering	$1,890,311.92	5.33%	$12.16	$11.26	7.71%	High Cost			
Vegetation Management	$908,822.55	2.56%	$5.84	$15.53	-97.70%	Far Better than Average	$28.73	-92.60%	Far Better than Average
Distribution Station Equipment	$735,110.13	2.07%	$4.73	$5.25	-10.43%	Better than Average			
Billing Operations	$4,309,297.77	12.14%	$27.71	$56.98	-72.09%	Far Better than Average			
General Expenses and Administration	$13,294,116.89	37.46%	$85.49	$116.83	-31.23%	Far Better than Average	$126.83	-31.10%	Far Better than Average
Load Dispatching	$1,531,766.01	4.32%	$9.85	$5.05	66.72%	Very High Cost			
Miscellaneous Distribution Expense	$2,560,771.36	7.22%	$16.47	$12.47	27.81%	Very High Cost			
Maintenance Supervision and Engineering	$1,799,061.01	5.07%	$11.57	$4.41	96.51%	Very High Cost			
Other	$5,891,598.38	16.60%	$37.89	$21.93	54.67%	Very High Cost			

The table is also just an example for a single distributor. There is a pull-down menu that will allow a user to select any of the Ontario distributors for analysis. The model will then repopulate the table with new results. This preliminary model has almost 70 cost per customer and unit cost metrics for each of 66 distributors in 2016. This database provides a considerable amount of information that can be drawn upon by parties seeking to better understand distributor cost levels. At some point during the APB process, it is expected that parties will have an opportunity to comment on the how to improve the presentation and functionality of this tool.

5.2.2. Econometric Research

We have developed econometric cost models for total OM&A expenses, some major components thereof, total capital cost, and total capex. Summary results from this research can be found in Table 2. The following results from this table are noteworthy.

- The explanatory power of the models was generally quite high at the initial stages of disaggregation.

Table 2

Granular Econometric Benchmarking Results Summary

Cost Granularity	R-Squared	Outliers: Number over/under by 40%+	Number over/under by 60%+	Number over/under by 100%+
Total Capital Cost	**0.974**	**10**	**4**	**1**
Capital Expenditures	**0.915**	**14**	**7**	**3**
Total OM&A	**0.965**	**7**	**4**	**1**
Distribution Network O&M	**0.901**	**18**	**7**	**4**
Load Dispatching	**0.870**	**40**	**38**	**31**
Distribution Operation Supervision and Engineering	**0.548**	**31**	**22**	**10**
Distribution Station Equipment O&M	**0.856**	**13**	**5**	**2**
Maintenance Poles Towers and Fixtures	**0.340**	**19**	**11**	**3**
Line O&M	**0.800**	**31**	**18**	**6**
Vegetation Management	**0.571**	**24**	**13**	**7**
Metering O&M	**0.721**	**23**	**10**	**3**
Customer Services	**0.943**	**10**	**3**	**0**
Collection	**0.597**	**35**	**25**	**14**
Billing	**0.841**	**17**	**7**	**1**
Administrative and General	**0.880**	**6**	**5**	**1**

- The explanatory power of the models for the major subcategories of OM&A cost which are currently reported in rebasings (e.g., billing and collection) is also high.
- Explanatory power tends to decline, however, when granularity increases.

Examination of individual models reveals that it is sometimes possible to identify numerous cost driver variables with statistically significant and plausibly signed parameter estimates. In some cases, the results emphasize the need for multidimensional scale indexes and consideration of additional business conditions in benchmarking.

Table 3 shows details of our preliminary econometric model of line O&M expenses as an example of this work. Additional econometric cost models we have developed for this project can be found in the Appendix. Examining Table 3, it can be seen that the number of customers served and circuit-kilometers of line are both statistically significant scale variables. System age and the extent of overheading are also statistically significant cost drivers. The -0.019 parameter on the time trend variable indicates that cost has been declining over time for reasons other that the trends in the four included business condition variables. This model provides the basis for multidimensional unit cost indexes and sheds light on the need for custom unit cost peer groups. It can also be used for direct econometric benchmarking.

Table 3

Econometric Model: Line O&M

VARIABLE KEY

Scale Variables:	yn =	Number of customers
	line =	Circuit-kilometers of line
Business Conditions:	yngrowth =	Percentage change in number of customers over last ten years
	pctoh =	Percentage of line that is overhead
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn*	0.556	14.262	0.000
line*	0.482	14.381	0.000
yngrowth*	-0.617	-2.874	0.004
pctoh*	0.717	12.509	0.000
Trend*	-0.019	-2.711	0.004
Constant*	4.233	112.281	0.000
System Rbar-Squared	0.850		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

6. An Illustrative APB Framework

PEG has developed an illustrative APB framework for the consideration of OEB Staff and stakeholders to stimulate thinking and discourse. This framework is supported by our analysis in this paper.

6.1 Benchmarking Methods

The OEB has decided to make unit cost benchmarking the featured methodology for APB. Some costs will be benchmarked using traditional unit cost metrics while others may be benchmarked using cost/volume metrics. Unit cost benchmarking methods are preferred by utilities and also spark the interest of some consumer advocates. Practitioners without special statistical training can try their hand at benchmarking and learn from the experience. Econometric models are viewed skeptically by many utility managers, and this reduces the likelihood that managers will use their results in cost control.[38]

We believe that econometric modelling can nonetheless play a constructive complementary role in the benchmarking of many granular costs. As recently acknowledged by an expert witness for both Hydro One and Toronto Hydro, econometric modelling is generally more accurate for benchmarking than unit costs and peer groups. Large datasets will accumulate in Ontario that facilitate econometric model estimation. For a statistical cost research specialist like PEG, econometric benchmarking is also be generally easier to undertake than testimony-quality unit cost studies, which often require custom peer groups or statistical adjustments. Statistical tests of the significance of cost driver variables and efficiency scores are straightforward. These tests are quite useful in the context of granular cost benchmarking since pertinent cost drivers are less well understood and itemization inconsistencies also complicate performance appraisals.

Direct econometric benchmarking results are a useful point of comparison to unit cost results. If econometric models explain data poorly, this may indicate that accurate benchmarking will also be difficult using unit cost metrics. Focus should instead be placed on more promising cost categories for benchmarking. Econometric models can (simultaneously) benchmark *volumes* of capex as well as *cost/volume* performance. Costs that are driven by several scale variables (e.g., where customers and

---

[38] However, part of their skepticism with total cost benchmarking is likely also due to the capital cost calculations, which are quite different from those used in revenue requirement calculations. This would not be a problem in econometric opex benchmarking.

line miles both matter a lot) can be benchmarked by unit cost metrics featuring multidimensional scale indexes with econometric weights. Econometric modelling can also be used to identify statistically significant additional cost drivers that are germane in peer group selection.

Another important methodological issue is whether special engineering models should be developed for capex like those which the AER uses for augex and repex. Models like these have been used by utilities and regulators but are complex and would involve large development costs. Key variables used in such models (e.g., share of assets nearing replacement age) could alternatively be used as explanatory variables in econometric capex models.

6.2 Costs Benchmarked

Granular benchmarking can require extensive additional data collection and itemization challenges. Which costs to benchmark is thus another critically important issue in the development of an APB strategy. The OEB Staff is developing a short list of granular costs that, after consultation with PEG and industry stakeholders, it believes are promising candidates for APB. We believe that benchmarking at some higher levels of aggregation also merits consideration.

- Total opex is an important focus of the AER benchmarking program. The OEB should consider benchmarking total opex and, since the data are already available in Ontario, should also consider benchmarking total capital cost and capex. Benchmarking these broad subaggregates would sidestep itemization and other cost reporting challenges and shed considerable additional light on the cost management of Ontario LDCs. For example, some LDCs requesting high capex budgets may currently have low capital costs or an unusual need for capex that econometric benchmarking can substantiate. The incremental cost of benchmarking total opex, capital cost, and capex modelling is modest and the benefits can be sizable. The results would certainly be pertinent in this APB project and much of the required work has already been done.
- The OEB should also consider benchmarking distribution O&M, customer service O&M, and administrative and general O&M expenses. As noted above, LDCs are required to report these costs in rebasing applications and non-reporting problems and new data requirements are minimal.

Illustrative cost categories for benchmarking are set forth in Table 4. We note for each cost category sensible scale variables and other variables that drive these costs. Illustrative cost categories

Table 4

Illustrative Cost Categories for Cost Benchmarking

Cost Categories [1] ***($mm 2016 agg)***	***Scale Metrics***	***Other Possible Cost Drivers***
Total OM&A Expenses	Customers, Peak Demand, Line Length, Substation Capacity	System Age, Forestation, % Plant Underground, Reliability
Distribution (783)	Customers, Peak Demand, Line Length, Substation Capacity	System Age, Forestation, % Plant Underground, Reliability
Lines, Line Transformers, and Structures (215)	Customers, Peak Demand, Line Length	System Age, Forestation, % Plant Underground, Reliability
Right of Way (171)	Overhead Line Length	System Age, Forestation, % Plant Underground, Reliability
Metering & Meter Reading (72)	Customers	Meter Types, Meter Age
Billing and Collecting (264)	Customers	Unemployment Rate, Number of Languages Spoken, Poverty Rate, Median Income
Billing (117)	Customers	Unemployment Rate, Number of Languages Spoken, Poverty Rate, Median Income
Administrative & General (531)	Customers, Peak Demand, Line Length, Employees, Substation Capacity	Percentage of Assets/Revenues that are Power Distribution, Reliability
Total Capital Cost	Substation Capacity, Customers, Peak Demand, Line Length	System Age, % Plant Underground, Reliability
Total Capex (2,160)	Customers, Growth Customers, Peak Demand, Line Length	System Age, % Plant Underground, Reliability
System Access [2]	Customers, Growth Customers, Line Length	% Services Underground, Reliability
System Renewal [2]	Customers, Peak Demand, Line Length	System Age, % Plant Underground, Reliability
System Service [2]	Customers, Peak Demand, Line Length	% Plant Underground, Share of Plant at Full Capacity, Reliability

[1] Supervision and Engineering expenses would be allocated proportionately to the functional categories.
[2] Development of these models would require the collection of new cost data.

for unit OM&A cost indexes are provided in Table 5. In this table, we note for each cost category sensible scale variables and other cost drivers. A multidimensional scale index is denoted by "YNDX."

An important issue facing the OEB is whether to gather the additional itemized cost and volume data that are needed to calculate program cost/volume metrics. We have seen that this type of benchmarking is used extensively by the AER and Ofgem. It may make sense to explore the costs and benefits of cost/volume metrics by trying it first for just a few cost categories (e.g., pole replacement).

Table 5

Illustrative APB Cost Groupings: Unit OM&A Cost Benchmarking

Cost Categories	*Scale Metrics*	*Other Cost Drivers* [1]
Distribution Networks	Distribution YNDX	Forestation, Age of Plant
Load Dispatch	Distribution YNDX	
Stations		
Station Buildings and Fixtures Expense	Station Capacity	Age of Station Plant
Transformer Station Equipment - Operation Labour	Station Capacity	Age of Transformer Station Plant
Transformer Station Equipment - Operation Supplies and Expenses	Station Capacity	Age of Transformer Station Plant
Distribution Station Equipment - Operation Labour	Station Capacity	Age of Distribution Station Plant
Distribution Station Equipment - Operation Supplies and Expenses	Station Capacity	Age of Distribution Station Plant
Maintenance of Buildings and Fixtures - Distribution Stations	Station Capacity	Age of Distribution Station Plant
Maintenance of Transformer Station Equipment	Station Capacity	Age of Transformer Station Plant
Maintenance of Distribution Station Equipment	Station Capacity	Age of Distribution Station Plant
Lines		
Overhead Lines		
Overhead Distribution Lines and Feeders - Operation Labour	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Overhead Subtransmission Feeders - Operation	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Overhead Distribution Lines and Feeders - Right of Way	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Overhead Distribution Lines and feeders - Rental Paid		Age of Lines, Forestation, Ice Storm, Line Length
Maintenance of Poles, Towers and Fixtures	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Maintenance of Overhead Conductors and Devices	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Maintenance of Overhead Services	Overhead Line Length	Age of Lines, Forestation, Ice Storm, Line Length
Underground Lines		
Underground Distribution Lines and Feeders - Operation Labour	Underground Line Length	Age of Lines, % Lines Urban
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	Underground Line Length	Age of Lines, % Lines Urban
Underground Subtransmission Feeders - Operation	Underground Line Length	Age of Lines, % Lines Urban
Maintenance of Underground Conduit	Underground Line Length	Age of Lines, % Lines Urban
Maintenance of Underground Conductors and Devices	Underground Line Length	Age of Lines, % Lines Urban
Maintenance of Underground Services	Underground Line Length	Age of Lines, % Lines Urban
Underground Distribution Lines and Feeders - Rental Paid		
Line Transformers		
Overhead Distribution Transformers- Operation	Customers	Age, Number, and Capacity of Transformers
Underground Distribution Transformers - Operation	Customers	Age, Number, and Capacity of Transformers
Maintenance of Line Transformers	Customers	Age, Number, and Capacity of Transformers
Meters		
Meter Expense	Customers	Type of Meter
Maintenance of Meters	Customers	Type of Meter
Meter Reading	Customers	Type of Meter
Customer Premises		
Customer Premises - Operation Labour	Customers	Age of Assets
Customer Premises - Materials and Expenses	Customers	Age of Assets
Sentinel Lights - Labour	# of Sentinel Lights	Age of Assets
Sentinel Lights - Materials and Expenses	# of Sentinel Lights	Age of Assets
Maintenance of Other Installations on Customer Premises	Customers	Age of Assets
Other Distribution Network Expenses		
Operation Supervision and Engineering	Distribution YNDX	Forestation, Age of Plant
Maintenance Supervision and Engineering	Distribution YNDX	Forestation, Age of Plant
Miscellaneous Distribution Expenses	Distribution YNDX	Forestation, Age of Plant
Other Rent	Distribution YNDX	Forestation, Age of Plant

Table 5 Continued

Illustrative APB Cost Groupings: Unit OM&A Cost Benchmarking

Cost Categories	*Scale Metrics*	*Other Cost Drivers* [1]
Billing and Collecting	Distribution YNDX	
Supervision	Customers	
Customer Billing	Customers	Number of Languages Spoken by Customers
Collecting	Customers	Unemployment Rate, Median Income
Collecting- Cash Over and Short	Customers	Unemployment Rate, Median Income
Collection Charges	Customers	Unemployment Rate, Median Income
Bad Debt Expense	Customers	Unemployment Rate, Median Income
Miscellaneous Customer Accounts Expenses	Customers	
Administrative and General	Administrative YNDX	
Management	Administrative YNDX	
Executive Salaries and Expenses	Administrative YNDX	
Management Salaries and Expenses	Administrative YNDX	
General Administrative Salaries and Expenses	Administrative YNDX	
Office Supplies and Expenses	Administrative YNDX	
Administrative Expense Transferred/Credit	Administrative YNDX	
Regulatory	Administrative YNDX	
Employee-Related	Administrative YNDX	
OMERS Pensions and Benefits / Employ. Pensions and Benefits	Administrative YNDX	Number of Employees
Employee Pensions and OPEB	Administrative YNDX	Number of Employees
Injuries and Damages	Administrative YNDX	
Employee Sick Leave	Administrative YNDX	Number of Employees
Other A&G Expenses	Administrative YNDX	
General Advertising Expenses	Administrative YNDX	
Outside Services Employed	Administrative YNDX	
Property Insurance	Administrative YNDX	
Franchise Requirements	Administrative YNDX	
Rent	Administrative YNDX	
Lease Payment Expense	Administrative YNDX	
Underground Distribution Lines and Feeders - Rental Paid	Administrative YNDX	
Overhead Distribution Lines and Feeders - Rental Paid	Administrative YNDX	
Other Rent	Administrative YNDX	
Miscellaneous General Expenses	Administrative YNDX	
Maintenance of General Plant	Administrative YNDX	Age of General Plant

[1] Input prices are pertinent for all categories.

6.3 New Data Rules

The effectiveness of APB in Ontario can be materially improved by the following upgrades to the data program.

- Distributors should be urged to itemize RRR OM&A expenses more carefully and consistently.
- LDCs should be required to itemize on their rebasing applications some more of the granular costs that the OEB wishes to benchmark. These itemizations should be consistent with RRR guidelines.
- While distributors are required to provide their capitalization policies and capitalization rates of overheads as part of a rate rebasing, benchmarking would be aided if distributors were to operate under more similar capitalization policies.

6.4 New and Improved Variables

We also believe that the OEB should expand data collection to support APB. A short list of recommended upgrades includes the following.

- Data filed in rate applications which the OEB wishes to benchmark but which are not currently reported on the RRR should be reported annually. Gross plant additions would be itemized by at least major functional asset categories going forward and, ideally, for several past years. For at least the first year that itemized gross plant additions are reported, it would also be desirable to itemize accumulated depreciation and amortization expenses so that calculation of itemized capital costs can begin. These data would make it possible to benchmark functionally itemized capex and lay the groundwork for future benchmarking of capital cost by type of plant. Total gross plant additions can be disaggregated into additions for system access, system renewal, system service, and general plant.
- Data should be gathered on some additional characteristics of plant in service and on some additional external business conditions that may be important drivers of some granular costs. Table 6 identifies some new data that would be useful in APB. High priority items are marked with a star. These include better peak demand data and data on forestation and substation capacity.
- It would be desirable for distributors to submit data on the new variables for several historical years where this is practicable. The number of historical years can vary by company. For some variables, estimates of actual values should be permitted, especially for past years.

6.5 Use of Benchmarking Results

Our review of benchmarking precedents in other jurisdictions has shown that the AER and Ofgem have used benchmarking to rationalize costs under review. Benchmarking is currently used in Ontario to set the stretch factors of price cap indexes but not to set rates in the first year of IRMs.

We have seen that granular benchmarking can be particularly difficult to do accurately. A balance of considerations suggests that the OEB move expeditiously to develop an APB framework and to use results cautiously in the early years. Distributors with good cost performance may obtain fast-track approval of these costs in rebasings. Unfavorable results can help the OEB focus on problem areas

Table 6

New Variables to Consider for Benchmarking

Cost

“Volumes” of capex and opex activities (e.g., number of poles inspected or transformers added)

System Characteristics

*Non-coincident peak demand of local networks

*MVA of substation capacity

*Share of substation and line capacity approaching full utilization

Structure miles of line (subtransmission and distribution)

- Overhead
- Underground

Number of line transformers (overhead and pad-mounted)

Embedded or host utility status

Length of services (overhead, underground)

System Age Variables

*Share of assets near end of service life by asset type
Share of assets requiring capacity augmentation
Asset failures by type of asset
Asset health index

Other Variables

*Forestation variables

- Number of vegetation management spans
- Share of overhead line spans in forested areas

Line length with standard vehicle access

Length of vegetation management cycle

Pole inspection cycle

Best weather station for weather data

Prevalence of pole footing conditions (e.g., soil, rock, or swamp, lacustrine)

in rate applications. The accuracy of APB should improve with accumulating data and experience.

Appendix

A.1 Further Details of Australian Benchmarking

A.1.1 Economic Benchmarking Data

In addition to cost data, the economic benchmarking RINs of the AER request data on numerous output dimensions including the following:

- Energy delivered and received (itemized by service class and time of day)
- Customer numbers (itemized by service class and location)
- Number of entry and exit points by voltage level
- System peak demand at zone substations and transmission connection points (coincident and non-coincident; raw and weather-adjusted; MW and MVA measure).

Data are also gathered on the scale of various physical assets LDCs own, including

- Overhead and underground circuit line length (km) and capacity (MVA) itemized by voltage
- Route line length (km)
- Distribution transformer capacity (MVA)
- Zone substation transformer capacity (MVA)
- Public lighting facilities (number of luminaires, poles, and columns).

Itemized data are gathered on the estimated service lives of new assets and the estimated weighted average remaining service lives of assets.

Economic benchmarking RINs also request data on reliability (SAIDI and SAIFI, with and without major event days), system losses, a summary metric on utilization of zone transformer substation capacity, and miscellaneous business condition (e.g., weather and terrain) variables which the AER calls "operating environment factors." These include the following "terrain factors":

- Number of vegetation management spans (urban, rural)
- Average urban and rural vegetation maintenance cycle

- Average number of trees per vegetation management span (urban, rural)
- Average number of defects per vegetation management span (urban, rural)
- Number of spans in tropical areas
- Number of spans subject to bushfire risk
- Length of line with standard vehicle access
- Weather stations in the service territory.

A.1.2 Category Analysis Data

The AER gathers itemized data for numerous kinds of capex and opex.

Capex

Augmentation Capex The category analysis RIN requests detailed augex data on certain assets. Unit cost metrics (e.g., capex per MVA of substation capacity) are pertinent for some kinds of augex and require data on the volume of plant additions where pertinent as well as their cost. Extensive supplemental data are gathered on peak demand by substation.

Replacement Capex LDCs must report repex and volumes of replacements and asset failures for numerous asset categories. There is extensive further itemization. For example, data are requested on eighteen kinds of poles, eight kinds of overhead conductors, and forty-one kinds of transformers. For detailed repex categories, supplemental data are gathered on system age variables that include the expected mean and standard deviation of asset lives and the number of assets installed in each year since 1901.

Customer-Initiated Expenses Customer-initiated expenses are demand-related expenses triggered by customer service requests. Expenses and volumes are requested for several kinds of assets (e.g., connections). The connections data are extensively itemized since connections vary considerably in voltage, may be overhead or underground, and may involve augmentation of other parts of the distribution system (e.g., distribution substations).

Opex

Vegetation Management Vegetation management expenses are itemized, for various zones (e.g., the "Alice Springs Region"), with respect to various activities (e.g., tree trimming and vegetation corridor clearance).

A.1.3. Categories Analysed

Cost categories considered and benchmarking methods used in the AER's category analysis are summarized in Table A-1.

Table A-1

Cost Categories Addressed by Australian Category Analysis

Cost Categories	Specific Subcategories	Benchmarking Methods
Augmentation Capex		Asset utilization engineering model
Replacement Capex		Engineering model reliant on asset ages and asset failure probabilities
Customer-Initiated Works by Customer Class	Customer Connections (Capex)	Specific method(s) not discussed in decisions
	Meter activities associated with a new connection (Capex)	Specific method(s) not discussed in decisions
	Augmentation of shared network by customer request or due to new customer connection (Capex)	Specific method(s) not discussed in decisions
	Fee-based services (Opex)	Specific method(s) not discussed in decisions
	Public Lighting Installation, Replacement, & Maintenance (Capex and Opex)	Specific method(s) not discussed in decisions
Non-Network Expenditure Capex and Opex	IT and Communications	Specific method(s) not discussed in decisions
	Motor Vehicles	Specific method(s) not discussed in decisions
	Property	Specific method(s) not discussed in decisions
	SCADA and Network Control	Specific method(s) not discussed in decisions
	Other	Specific method(s) not discussed in decisions
Labour opex (Internal costs)		Cost per average staffing level (e.g., the number of full time employees or equivalent), Average staffing level per 100,000 customers
Overheads: Indirect operating expenditures including administrative and general expenses	Total	Cost per customer
	Corporate	Cost per customer
	Networks	Cost per circuit kilometer, Cost per customer
Vegetation Management (Opex)		Cost per kilometer of overhead route line length
Maintenance (Opex)		Cost per circuit kilometer
Emergency Response (Opex)		Cost per interruption

A.2 Further Details of Ofgem's Benchmarking

Table A-2 provides a list of the cost areas and subcategories addressed by Ofgem's disaggregated benchmarking. The data relied upon varied with the activity, as some activities were assessed using all 13 years of data while others relied on only the forecast or the historical data. Forecasts were favored to the extent that there were discernible cost trends.

Table A-2

Cost Categories Addressed by Ofgem's Disaggregated Benchmarking

Cost Areas	**Cost Subcategories**
Network Operating Costs	Responses to Outage Calls: [Resolution of faults which are interruptions and occurrences not incentivised ("ONIs"). Interruptions can cause customers to be without supply, whereas ONIs generally do not cause customers to be without supply.]
	Severe Weather (1 in 20) Events
	Inspections and Maintenance
	Tree Cutting (e.g., vegetation management and tree trimming)
	Other (includes substation consumed electricity, dismantlement and remote location generation)
Load-related capex	Reinforcements
	Transmission Connection Point Charges (Investment costs relating to points at which the distribution network connects to the transmission network)
	Connections: New or upgraded network exit point to a new or existing customer, includes DG
Asset replacement, refurbishment, and civil works capex	Asset replacement capex
	Asset refurbishment capex
	Civil works capex
	High Value Projects (Major projects where the related capex is forecast to exceed the high value project threshold as determined by Ofgem)
Non-core non-load-related capex (Installation of new network assets and planned installation of replacement network assets for reasons other than load-related reasons)	Operational IT & Telecoms (Equipment which is used exclusively in the real time management of network assets, but which does not form part of those network assets)
	Diversions (Costs to secure easements, compensate owners of nearby land for loss of value due to asset installation, or divert assets to new areas once a right of way is lost)
	Electricity Safety, Quality and Continuity Regulations (broken further into 28 separate subcategories)
	Legal and Safety (Any investment or intervention where the prime driver is to meet safety requirements and to protect staff and the public. It does not include assets replaced because of condition assessment or to meet Electricity Safety Quality and Continuity of Supply Regulations)
	Substation Flood Resilience
	BT21C (British Telecom's rollout of next generation communications network)
	Losses and Environment (Projects that improve visual amenity; mitigate oil, SF6, and noise pollution; and clean up contaminated land)
	Critical National Infrastructure
	Black Start
	Rising and Lateral Mains: any expenditure on individual distributor-owned three phase cable or busbar, not laid in the ground, which runs within or is attached to the outside of a multiple occupancy building.
	Improved Resilience for Worst Served Customers

Table A-2 (continued)

Cost Categories Addressed by Ofgem's Disaggregated Benchmarking

Cost Area	Cost Subcategories
Closely associated indirect expenses, business support expenses, and non-operational capex	CEO and Group Management
	Network Design and Engineering
	Project Management
	System Mapping
	Engineering Management and Clerical Support
	Stores
	Network Policy
	Control Center
	Call Center
	Vehicles and Transport
	Operational Training & Workforce Renewal
	Streetworks
	Finance and Regulation
	HR and non-operational training
	IT & Telecoms
	Property
	Small Tools, Equipment, Plant and Machinery
	Vehicles and Transport

A.3 Ontario Data Tables

Table A-3

RRR Itemization of Electricity Distributor OM&A Expenses

OM&A Cost Categories			Account Number	Aggregate Value 2017
Distribution	Distribution Operation	Operation Supervision and Engineering	5005	$67,707,231
		Load Dispatching	5010	$41,801,248
		Station Buildings and Fixtures Expense	5012	$7,562,642
		Transformer Station Equipment - Operation Labour	5014	$2,500,780
		Transformer Station Equipment - Operation Supplies and Expenses	5015	$1,468,000
		Distribution Station Equipment - Operation Labour	5016	$12,025,135
		Distribution Station Equipment - Operation Supplies and Expenses	5017	$9,378,328
		Overhead Distribution Lines and Feeders - Operation Labour	5020	$28,274,170
		Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	$7,628,284
		Overhead Subtransmission Feeders - Operation	5030	$804,687
		Overhead Distribution Transformers- Operation	5035	$1,046,598
		Underground Distribution Lines and Feeders - Operation Labour	5040	$7,091,013
		Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	$10,845,893
		Underground Subtransmission Feeders - Operation	5050	$10,571
		Underground Distribution Transformers - Operation	5055	$1,608,319
		Street Lighting and Signal System Expense	5060	$6,709
		Meter Expense	5065	$33,683,859
		Customer Premises - Operation Labour	5070	$32,469,485
		Customer Premises - Materials and Expenses	5075	$7,892,279
		Miscellaneous Distribution Expense	5085	$57,347,971
		Underground Distribution Lines and Feeders - Rental Paid	5090	$49,341
		Overhead Distribution Lines and Feeders - Rental Paid	5095	$947,710
		Other Rent	5096	$812,832
		Total Operations		**$332,963,085**
	Distribution Maintenance	Maintenance Supervision and Engineering	5105	$33,120,447
		Maintenance of Buildings and Fixtures - Distribution Stations	5110	$17,983,791
		Maintenance of Transformer Station Equipment	5112	$4,912,566
		Maintenance of Distribution Station Equipment	5114	$25,930,192
		Maintenance of Poles, Towers and Fixtures	5120	$25,632,601
		Maintenance of Overhead Conductors and Devices	5125	$86,298,391
		Maintenance of Overhead Services	5130	$10,990,012
		Overhead Distribution Lines and Feeders - Right of Way	5135	$158,004,640
		Maintenance of Underground Conduit	5145	$2,189,379
		Maintenance of Underground Conductors and Devices	5150	$26,886,080
		Maintenance of Underground Services	5155	$8,803,716
		Maintenance of Line Transformers	5160	$7,114,806
		Maintenance of Street Lighting and Signal Systems	5165	$4,166,158
		Sentinel Lights - Labour	5170	$421,193
		Sentinel Lights - Materials and Expenses	5172	$110,915
		Maintenance of Meters	5175	$8,218,802
		Maintenance of Other Installations on Customer Premises	5195	$0
		Total Maintenance		**$420,783,688**
		Total Operation and Maintenance		**$753,746,773**

Table A-3 (continued)

RRR Itemization of Electricity Distributor OM&A Expenses

RRR Itemization of Power Distributor OM&A Expenses

OM&A Cost Categories		Account Number	Aggregate Value 2017
Billing and Collecting	Supervision	5305	$16,866,155
	Meter Reading Expense	5310	$35,806,744
	Customer Billing	5315	$123,109,569
	Collecting	5320	$48,716,049
	Collecting - Cash Over and Short	5325	$5,373
	Collection Charges	5330	-$823,662
	Bad Debt Expense	5335	$36,979,834
	Miscellaneous Customer Accounts Expenses	5340	$20,318,748
	Total Billing and Collecting		**$280,978,810**
Community Relations	Supervision	5405	$1,856,847
	Community Relations - Sundry	5410	$9,322,537
	Energy Conservation	5415	$508,020
	Community Safety Program	5420	$4,117,610
	Miscellaneous Customer Service and Informational Expenses	5425	$1,529,643
	Total Community Relations		**$17,334,656**
Sales	Demonstrating and Selling Expense	5510	$217,741
	Advertising Expense	5515	$142,680
	Total Sales Expenses		**$360,421**
Administrative and General Expenses	Executive Salaries and Expenses	5605	$50,104,683
	Management Salaries and Expenses	5610	$91,760,127
	General Administrative Salaries and Expenses	5615	$167,705,769
	Office Supplies and Expenses	5620	$16,384,303
	Administrative Expense Transferred/Credit	5625	-$99,173,084
	Outside Services Employed	5630	$52,307,661
	Property Insurance	5635	$10,041,763
	Injuries and Damages	5640	$8,212,293
	OMERS Pensions and Benefits / Employ. Pensions and Benefits	5645	$10,746,526
	Employee Pensions and OPEB	5646	$3,541,592
	Employee Sick Leave	5647	-$16,800
	Franchise Requirements	5650	$63,400
	Regulatory Expenses	5655	$31,204,535
	General Advertising Expenses	5660	$1,745,339
	Miscellaneous General Expenses	5665	$57,530,854
	Rent	5670	$14,531,795
	Lease Payment Expense	5672	$0
	Maintenance of General Plant	5675	$144,833,509
	Electrical Safety Authority Fees	5680	$993,910
	Special Purpose Charge Expense	5681	$0
	Independent Market Operator Fees and Penalties	5685	$93,307
	OM&A Contra	5695	-$1,058,038
	Total Administrative and General Expenses		**$561,553,444**
Total OM&A Expenses			**$1,613,974,104**

Note: (1) Costs that are especially difficult to benchmark are italicized.
(2) Some of Alectra's January 2017 cost accounts were unavailable.

Table A-4

RRR Data on Electricity Distributor Plant Value

RRR Itemization of Power Distributor Gross and Net Plant Value

Gross Plant Value		Account Number	Aggregate Value 2017
Distribution	Computer Software merged with Account 1925	1611	$550,786,489
	Land Rights merged with Accounts 1806 and 1906	1612	$266,978,853
	Land	1805	$125,176,354
	Buildings and Fixtures	1808	$387,696,953
	Leasehold Improvements	1810	$16,932,549
	Transformer Station Equipment - Normally Primary above 50 kV	1815	$701,984,887
	Distribution Station Equipment - Normally Primary below 50 kV	1820	$1,478,642,090
	Storage Battery Equipment	1825	$1,232,995
	Poles, Towers and Fixtures	1830	$5,390,365,662
	Overhead Conductors and Devices	1835	$3,727,247,597
	Underground Conduit	1840	$2,199,862,895
	Underground Conductors and Devices	1845	$3,619,461,941
	Line Transformers	1850	$4,069,999,412
	Services	1855	$763,997,477
	Meters	1860	$1,415,785,720
	Other Installations on Customer's Premises	1865	$428,733
	Leased Property on Customer Premises	1870	$0
	Street Lighting and Signal Systems	1875	$2,157,258
	Load Management Controls - Customer Premises	1970	$5,766,411
	Load Management Controls - Utility Premises	1975	$2,459,653
	System Supervisory Equipment	1980	$255,434,147
General	Land	1905	$77,795,502
	Buildings and Fixtures	1908	$663,008,712
	Leasehold Improvements	1910	$37,618,072
	Office Furniture and Equipment	1915	$62,537,479
	Computer Equipment - Hardware	1920	$204,173,983
	Transportation Equipment	1930	$473,832,145
	Stores Equipment	1935	$5,124,693
	Tools, Shop and Garage Equipment	1940	$77,120,857
	Measurement and Testing Equipment	1945	$20,213,763
	Power Operated Equipment	1950	$232,502,307
	Communication Equipment	1955	$110,859,461
	Miscellaneous Equipment	1960	$10,935,585
	Sentinel Lighting Rental Units	1985	$15,350,148
	Other Tangible Property	1990	$32,517,853
Total Gross Plant Value [A]			**$27,005,988,638**

Accumulated Amortization and Depreciation	Account Number	
Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment and Accumulated Amortization of Electric Utility Plant - PP&E [B]	2105	-$7,619,228,838
Accumulated Amortization of Electric Utility Plant - Intangibles [C]	2120	-$432,011,252

Net Value Capital Assets [D=A+(B+C)]	**$18,954,748,547**

Capital Asset Contributions	Account Number	
Capital Contributions Paid [E]	1609	$186,242,649
Contributions and Grants - Credit [F]	1995	-$892,537,911

Net Value of Capital Assets Less Capital Contributions [D+E+F]	**$18,248,453,285**
Gross Capital Additions	**$2,129,757,110**

Note: Alectra's January 2017 cost accounts (except gross capital additions) were unavailable.

Table A-5

Other Past or Present RRR Data that May Be Useful for Benchmarking

RRR E2.1.4 (Service Quality and Reliability)

- Number of connection requests (low voltage, high voltage)
- Percentage of connection requests where the connection is made within 5 working days
- Number of appointment requests
- Percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met
- Percentage of appointments rescheduled in the event that an appointment is missed or going to be missed
- Number of incoming calls
- Percentage of qualified incoming calls to the utility that are answered in person within 30 seconds
- Percentage of written responses provided within 10 days to qualified enquiries
- Number of emergency response (fire, police, ambulance) calls (urban, rural)
- Percentage of emergency calls where a qualified service person is on site within 60 minutes of the call (urban, rural)
- Number of reconnections
- Number of customers disconnected for non-payment who were reconnected completed in two days
- Percentage of new micro-embedded generation facilities connected to its distribution system within 5 business days
- SAIDI and SAIFI

RRR E2.1.5.1 (Labour)

- Number of full time equivalent employees
- Average number of employees and total salaries and wages charged to current operating expenses
- Average number of employees and total salaries and wages charged to new construction

RRR E2.1.5.2 (Capital)

- Total capital additions (gross capial additions, retirements, contributed capital, other)
- High voltage capital additions (gross additions, retirements, contributed capital, other)
- Capital expenditures (direct labour, equipment and materials, contract services, capitalized overhead, other)

RRR E2.1.5.5 (Utility Characteristics)

Total service territory area (total, rural, urban)	Circuit km of line (overhead, underground, total)
Summer peak load (with and without embedded generation)	Average load factor (with and without embedded generation)
Winter peak load (with and without embedded generation)	Average peak load (with and without embedded generation)

RRR E2.1.8 (Customer Service)

Number of eligible low-income customer accounts	Number of residential customer accounts written-off in whole or in part
Number of residential customer accounts disconnected for non-payment	Number of residential customer accounts enrolled in equal billing plans
Number of eligible low-income customer accounts disconnected for nonpayment	Number of residential customer accounts with security deposits held
Number of customer accounts in arrears	Number of residential customer accounts where load limiter devices were installed
Billing frequency	

RRR E2.1.14 (Net Metering and Embedded Generation)

Number of net metering customers	Total installed net metering capacity

Table A-6

Required Opex Data in Ontario Rebasings

Summary of <u>Recoverable</u> OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis						
Operations						
Maintenance						
SubTotal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
%Change (year over year)						
%Change (Test Year vs Last Rebasing Year - Actual)						
Billing and Collecting						
Community Relations						
Administrative and General						
SubTotal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
%Change (year over year)						
%Change (Test Year vs Last Rebasing Year - Actual)						
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
%Change (year over year)						

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ -	$ -	$ -	$ -	$ -	$ -
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collecting	$ -	$ -	$ -	$ -	$ -	$ -
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
%Change (year over year)						

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	Variance 2013 Board-approved – 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2013 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collecting	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total OM&A Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Variance from previous year				$ -		$ -		$ -		$ -	
Percent change (year over year)											
Percent Change: Test year vs. Most Current Actual											
Simple average of % variance for all years											
Compound Annual Growth Rate for all years											
Compound Growth Rate (2016 Actuals vs. 2013 Actuals)											

Note:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

Table A-7

Required Capex Data in Ontario Rebasings

Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land				$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV				$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures				$ -				$ -	$ -
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices				$ -				$ -	$ -
47	1850	Line Transformers				$ -				$ -	$ -
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue [5]									
						$ -				$ -	$ -
		Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**$ -**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

A.4 Additional Econometric Models

A.4.1 Capital Cost

Below are two models addressing capital costs. Table A-8 is a model of total capital cost. Table A-9 evaluates capital expenditures. Both models are preliminary and could benefit from additional work. These models could provide a check on more granular capital cost metrics. They could assess which business conditions are important and by how much. One difference between the results of a total capital expenditure econometric model and capex cost-volume metrics like those used in Australia and Britain is that the latter will only address the cost efficiency of installing a given amount of capital assets whereas the former will also address whether the volume of capital assets installed was reasonable. Both questions are potentially of interest.

A.4.2 OM&A Expenses

Also included below are results of preliminary OM&A benchmarking models for three OM&A cost categories that distributors report in their rebasing applications. Table A-10 presents results for distribution O&M, Table A-11 presents results for customer service, and Table A-12 presents results for administrative and general expenses.

These types of models could potentially provide a check on the more granular metrics proposed. The models contain varying numbers of statistically significant business conditions. These business conditions can inform how to conduct additional analysis to interpret the unit cost results.

Table A-8

Econometric Model of Capital Cost

VARIABLE KEY

Scale Variables:	yn =	Number of customers
	line =	Circuit-kilometers of line
	peakr =	Ratcheted peak demand since 2002
Business Conditions:	pctoh =	Percentage of line that is overhead
	yngrowth =	Percentage change in number of customers over last ten years
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn*	0.798	29.250	0.000
line*	0.240	13.523	0.000
peakr*	0.090	2.976	0.003
pctoh	-0.033	-1.453	0.147
yngrowth*	0.217	5.026	0.000
Trend*	0.012	5.235	0.000
Constant*	14.408	875.766	0.000
System Rbar-Squared	0.974		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

Table A-9

Econometric Model of Capital Expenditure

VARIABLE KEY

Scale Variables:	line =	Circuit-kilometers of line
	peakr =	Ratcheted peak demand since 2002
	totdistran =	Number of distribution and transmission substations
Business Conditions:	ynaddx =	Change in number of customers over the sample period
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
line*	0.162	3.007	0.003
line·line*	-0.262	-11.318	0.000
peakr*	0.597	14.454	0.000
totdistran*	0.262	5.621	0.000
ynaddx*	0.601	10.554	0.000
Trend*	0.037	5.046	0.000
Constant*	10.759	194.840	0.000
System Rbar-Squared	0.924		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

Table A-10

Econometric Model of Distribution O&M Cost

VARIABLE KEY

Scale Variables:	yn =	Number of customers
	ohline =	Circuit-kilometers of overhead line
	ugline =	Circuit-kilometers of underground line
	peakr =	Ratcheted peak demand since 2002
	totdistran =	Number of distribution and transmission substations
Business Conditions:	yngrowth =	Percentage change in number of customers over last ten years
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn*	0.508	8.859	0.000
ohline*	0.270	15.751	0.000
ugline*	0.176	4.166	0.000
peakr	0.066	1.233	0.219
totdistran*	0.173	2.833	0.005
yngrowth*	-1.035	-7.843	0.000
Trend	-0.001	-0.134	0.893
Constant*	4.525	108.994	0.000
System Rbar-Squared	0.902		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

Table A-11

Econometric Model of Customer Service Cost

VARIABLE KEY

Scale Variables:	yn =	Number of customers
	line =	Circuit-kilometers of line
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn*	0.697	44.513	0.000
line*	0.133	9.438	0.000
Trend*	-0.026	-6.051	0.000
Constant*	3.903	189.786	0.000
System Rbar-Squared	0.943		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

Table A-12

Econometric Model of Administrative & General Cost

VARIABLE KEY

Scale Variables:	yn =	Number of customers
	peakr =	Ratcheted peak demand since 2002
Business Conditions:	pctoh =	Percentage of line that is overhead
	trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn*	0.611	19.666	0.000
peakr*	0.271	8.692	0.000
pctoh*	0.228	7.160	0.000
Trend*	0.010	2.291	0.023
Constant*	4.328	215.265	0.000
System Rbar-Squared	0.880		
Sample Period	2013-2017		
Number of Observations	325		

*Estimate is significant at the 95% confidence level

References

Australian Energy Regulator (2016). *Annual Benchmarking Report: Electricity Distribution Network Service Providers*, November.

Coelli, T. J., Rao, D. P., O'Donnel, C. J., & Battese, G. E. (2005). *An Introduction to Efficiency and Productivity Analysis*. New York, New York: Springer.

Dyson, R., Allen, R., Camanho, A., Podinovski, V., Sarrico, C., & Shale, E. (2001). "Pitfalls and Protocols in DEA." *European Journal of Operational Research*, pages 245-259.

Kaufmann, Lawrence, David Hovde, John Kalfayan, and Kaja Rebane (2013). *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board,* EB 2010-0379*.*

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