PHASE II REPORT

PART I
METHODOLOGY AND STUDY FINDINGS: COMPARATORS AND COHORTS STUDY FOR 2006 EDR

for the consideration of:

The Ontario Energy Board and Staff

by:

Robert Camfield

J. David Glyer, PhD

Philip Schoech, PhD

Michael Welsh, PhD

Christensen Associates Energy Consulting, LLC

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1.0 Introduction

In its 2006 Electric Distribution Rate ("EDR") proceeding, the Ontario Energy Board ("the Board") recognizes the near-term challenges associated with processing the rate applications of the numerous electric distributors in Ontario under conventional cost-of-service principles. As a consequence, the Board initiated the Comparators and Cohorts ("C&C") concept as a potential mechanism to help facilitate the review of the applications. As stated in the Board's May 11, 2005 EDR Report:[1]

> *The Board must find effective and efficient methods for assessing rate applications for over 90 electricity distributors. Administrative concerns regarding the volume of applications are important, but the need to find a technique to assist in establishing just and reasonable rates is even more important.*

Comparators and Cohorts can be defined in many ways. One definition of C&C is contained in CA Energy Consulting's initial report ("Phase I Report") to the Board filed in docket RP-2004-0188 proceeding, as follows:[2]

> *The notion of a Comparator refers to a cost dimension or cost indicator associated with the supply of—or, the process of supplying—distribution electricity service. The notion of a Cohort refers to a group of local distribution companies selected as reasonably similar based upon defined cost drivers.*

[1] Report of the Board, *2006 Electricity Distribution Rate Handbook*, RP-2004-0188, May 11, 2005.

[2] Findings and Recommendations: Comparators and Cohorts for Electricity Distribution Rates, December, 2004 (Phase I report).

As a cost indicator, a comparator is a metric, or measure of costs, that provides a means to compare the relative cost performance of individual Ontario distributors with reference to peers. Distributors with relatively high-cost performance are highlighted for further consideration by the Board and Board staff in its review of the rate applications. To this end, the comparators—and more generally, the C&C study as a whole—can seemingly serve as a tool to help enable Board staff to assess the rate applications of distributors. At the outset, a study of the relative cost performance of electric distributors according to predefined cost metrics, or comparators, should address two overarching concerns:

1. Adequately Account for Similarity of Underlying Characteristics and Business Context: The business context of individual distributors has impact on cost. One distributor may have higher costs than another because its business context is more costly to serve, not because it is inherently less efficient. Indeed, absent a sufficiently similar business context, a distributor that has the appearance of comparatively low costs may be the less efficient of the two. In short, it is inappropriate to compare the costs of distributors that are largely dissimilar. It is thus necessary to group Ontario's distributors into common characteristics of business context, such as: a) rural vs. urban systems, b) location in the southern region vs. remote northern areas, c) predominantly overhead vs. largely underground systems, and d) customer and load density.

2. Provide Comparator Metrics that Are Useful to Board Staff: There are innumerable possible cost indicators, or comparators. It is important to determine and report comparators that are most useful in the general inquiry by the Board and Board staff regarding the rate applications of Ontario distributors.

In summary, the task before us is to define and implement a C&C approach that objectively assigns electric distributors to peer groups, and then compares them according to useful comparator metrics.

Through its recent exploratory inquiry regarding C&C methodology, the Board has set forth a plausible approach to compare the costs of the electric distributors. The Board's C&C

methodology is defined in its Electricity Distribution Rate Handbook ("Rate Handbook") that accompanied the May 11, 2005 Report of the Board:[3]

> *The comparators and cohorts mechanism will be used to assist Board Staff to screen 2006 rate filings by the distributors. The mechanism provides a basis to determine comparable peer groups (Cohorts) and to compare the costs (Comparators) of the distributors in the Province.*
>
> *The Comparators and Cohorts Mechanism is defined as a four-step analytical procedure, as follows:*
>
> *1. <u>Screen and Organize LDC Data</u>: LDC data and information regarding costs, resource inputs, output quantities, and technology and business descriptors will be analyzed with modern statistical tools. Statistical tools and methods will be utilized to assess data quality (reliability, accuracy, and consistency), and to help understand relationships among data. For each of the unbundled services, the data will be organized according to defined cost categories.*
>
> *2. <u>Determine Cost Drivers with Econometric Methods</u>: Econometric methods will be utilized to determine the statistical relationships between cost categories and resource inputs, and cost drivers. Cost drivers include output quantities and unit-of-output quantities; and market context and technology descriptors (together referred to as business context).*
>
> *3. <u>Determine Cohorts with Clustering Methods</u>: Distributors will be assigned to Cohorts with cluster analysis. Cluster analysis will group LDCs according to similarity of cost drivers including output quantities and business context.*
>
> 4. *<u>Determine and Report Cost Comparators</u>: For pre-defined comparators, each distributor will be gauged according to its relative position within the statistical distribution of costs of the LDCs within its Cohort (peer group) and as a whole.*

Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") has been retained by the Board to assist in defining and developing a practical C&C mechanism which accords with the guidelines identified by the Board.

The above excerpts, to a substantial extent, define the overall objective and methodology of the current study. The methodology adopted by the Board and as codified in the Rate Handbook was put forth for consideration in the Phase I Report and follow-up filings in the Board's exploratory inquiry. The immediate report, referred to as "Phase II," constitutes the application of the methodology defined in Phase I.

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[3] Chapter 14, <u>Comparators and Cohorts</u>, *Electricity Distribution Rate Handbook*, RP-2004-0188, May 11, 2005.

At the outset of the Phase II work, changes in methodology were anticipated, mostly as a result of limitations of data.[4] However, the contemporary data set appears to be markedly improved with reference to the data available for Phase I work. As a consequence, the Phase II study approach closely adheres to the general methodology identified by the Board in its Rate Handbook, and as outlined in the Phase I Report.

Part I, Phase II Report. Section 2 of *Part I* of this Phase II report briefly reviews the LDC data and information utilized in the C&C analyses. Section 3 reviews the general conceptual design and C&C analysis steps, including a discussion of data screening. Section 4 provides a general review of electric distribution services and costs, and Section 5 defines unbundled distribution services and limitations to cost benchmarking, as conducted for unbundled services. Section 6 summarizes the analysis results. Section 7 provides concluding comments and recommendations for moving forward. *Part I* concludes with an Appendix that reviews economic cost theory. For the interested reader, a list of technical references is included at the end of *Part I*.

Part II, Phase II Report. Following a brief introduction, Section 2 of *Part II* of the Phase II report presents the empirical cost models. Section 3 presents the comparators and cohorts, including an accompanying discussion. Appendix I presents the results of a study of economies of scale and density, which are based upon the cost models developed as part of the Phase II work, and Appendix II reports the full model results of the simultaneous cost system used in the immediate study.

[4] The Board has recognized that the C&C mechanism is all new, and anticipates changes in methodology. *Section 14.0 Methodology* (for Comparators and Cohorts), of the Rate Handbook states:

> *The final specification of the cost driver models and the cohorts will be influenced by the data and may vary somewhat from the procedure outlined above.*

A second example of the Board's recognition of evolution in C&C methodology and, as implied, the need for flexibility is reflected in the May 11 Report of the Board in the instant docket, is as follows:

> *The Board is aware of the technical challenges involved, some of which were discussed by the experts. The Board accepts that developing these types of techniques will take time and will involve significant technical effort. However, the Board remains of the view that this is the appropriate direction to take in the rate regulation of Ontario electricity distributors.*

2.0 C&C Data and Information

2.1 PBR and Trial Balance Data

As emphasized by the Board and by the Phase I Report, it is necessary for the C&C data to reach a sufficient level of completeness and accuracy in order for the C&C approach, as outlined, to potentially satisfy the overall objectives set forth by the Board. The primary data source for the C&C analysis is the Performance-Based Regulation ("PBR") and Trial Balance ("TB") filings of the Ontario Local Distribution Companies (LDCs), which are available for the years 2000–2004. These data are filed by the LDCs with the Board under the Board's Reporting and Record-keeping Requirements ("RRR"). The PBR and TB filing requirements were newly introduced procedures at the time, and there were issues of interpretation and meaning of the reporting requirements, at a detailed level. During this timeframe, Ontario's electricity services industry was also undergoing substantial restructuring involving mergers and consolidation which, among other things, contributed to the need for a general overhaul of accounting, financial recordkeeping, and reporting. Finally, the Board introduced electronic systems to facilitate the process of reporting and managing the regulatory data and information filings made by the LDCs.

As a consequence of these factors, there was a general concern by participants involved in the 2006 EDR that the PBR and TB data may be compromised by an element of reporting inaccuracy. During March of 2005, the Board's Chief Regulatory Auditor via Letter of the Board requested that the LDCs review and confirm their PBR and TB filings for 2002 and 2003.[5] As a result, substantial revisions have been incorporated into the 2002–2003 PBR data. Board staff advises that these revisions bring the current PBR and TB data for these two years to a level that can serve as a starting point for the immediate C&C study. Along with the PBR and TB data for 2004 data, then, the Phase II study has available to it a fairly complete panel data set covering about 95 distributors over the 2002–2004 timeframe. These data cover the cost, technology, and underlying business context of the LDCs, including network characteristics and market situation.

[5] Board Letter with reference to *Confirmation of Information filed under the Board's Reporting and Record Keeping Requirements*, dated March 28, 2005.

2.2 Local Distribution Companies

The LDCs incorporated into the C&C analyses reported herein are listed in Table 1 shown toward the back of the Part I Report. On advice of Board staff, five LDCs including Attawapiskat, Fort Albany, Hydro One Networks, Hydro One Remote Communities, and Kashechewan are to be excluded from the C&C analysis at the outset of the study.

Hydro One Networks and Hydro One Remote Communities ("HORC") are subsidiaries of Hydro One Inc., as is Hydro One Brampton Networks. Hydro One Networks has acquired, by our count, 87 of Ontario's LDCs, and has developed an umbrella of activities and functions that have assumed some of the business functionality that would otherwise be carried out by the LDCs as individual entities. This business arrangement would appear to set Hydro One Networks apart from other LDCs in terms of cost behaviour and, potentially, the range of service options that can be provided to electricity consumers. In the case of Hydro One Remote Communities, both generation and transport services are provided to a number of remote communities, primarily First Nations in Northern Ontario. These communities are not connected to the provincial grid, and access to these communities is difficult—typically by air or water transport. In summary, HORC provides services to a small economic and customer base located in communities scattered remotely over large distances and with difficult access. This situation sets them apart as a joint generator-distributor. For regulatory purposes, HORC's circumstances and operating environment mean that rate-setting is handled differently than that of most utilities.

Attawapiskat, Fort Albany, and Kashechewan, known as First Nations distributors, are recently formed distributors serving communities in Northern Ontario as a result of a transmission line expansion along the James Bay shoreline. Until that time, HORC provided generation and distribution services to the communities. While these three LDCs have filed PBR and TB data for the available years since coming into existence, their data reveal a unique cost experience with respect to that of the other LDCs, possibly as a result of start-up, of an unusually small customer base in view of the size of the facilities (low customer density), and of the isolation of the served communities.

It is necessary also to exclude Westario Power and Newbury Power from the C&C analysis for all years because of the absence of PBR and TB data. In addition, CNPI and Cornwall Electric are also excluded from the immediate study, as we are unable to find recognizable patterns in key data necessary for C&C analysis. Finally, concerns of data accuracy have led to the exclusion of eight other LDCs, for selected years.

In summary, the PBR and TB data begins with coverage for 101 LDCs, including utilities that have restructured during the 2002–2004 period. For the reasons discussed above, the study covers 92 LDCs, which constitutes 268 observations across the three years. As mentioned above, the electricity distributors in Ontario incorporated into the analysis are listed in Table 2, pages 28-30 of Part I of the report.

3.0 Analysis Framework

3.1 Study Design

The general approach to C&C is based on two principles. First, there exist systematic, causal relationships between business context (characteristics), and the resources and costs of Ontario's electricity distributors including capital, labour, energy, and other inputs. Essentially, differences in the underlying business context determine resource cost differences among LDCs; the task at hand is to discern and understand the features of business context—cost drivers—that determine resources and costs. Second, features of business context, because they are interpreted to be largely outside the control of the LDCs, are an appropriate basis to group distributors into similar groups, or cohorts.

As mentioned above, the technical approach for the Phase II work follows the methodology adopted by the Board in its Report of May 2005 and Handbook. This methodology includes four analysis steps: 1) *screen and organize LDC data*; 2) *determine cost drivers with econometric methods*; 3) *determine cohorts with clustering methods*; and 4) *determine and report cost comparators*. These analysis steps are sequential. Once the data are verified and edited (Step 1, *screen data*), the relationships between cost drivers and resources are determined with statistical methods (Step 2, *econometrics*). Once determined, cost drivers are then used to group the LDCs into cohorts of peers (Step 3, *clustering to determine* *cohorts*). For each of the predefined comparators, each LDC is assessed—i.e., benchmarked—with reference to the average for its cohort or peer group (Step 4, *report comparators*).

Step 3 involves the estimation of s*ingle equation models* for Wires and Interconnection Services, and for Support Services including *Billings and Collections* and *Administrative and General*. This first approach involves a resource demand equation and a restricted cost equation, as determined for each of the two service categories. The resource demand equations are referred to as *capital resources (gross assets)*, while the restricted cost equations are referred to as *expenses (variable costs)*. Altogether, four single equation models are estimated, for purposes of determining cost drivers.

A second cost model approach utilized in the study is a *multiple (simultaneous) equation cost model*, which is determined for the all-in variable costs of Wires and Interconnection Services and Support Services together. This equation system is used to help identify the cost drivers, and also to estimate economies of scale and economies of density in LDC services, as reported in Technical Appendix I of Part II of the Phase II Report.

Once identified, the cost drivers of the cost equations are used to determine the cohort groups with clustering methods. Two cohort sets are reported:

> Set 1: LDC cohorts based upon identified cost drivers for Wires and Interconnection Services. Seven cohort groupings are determined.
>
> Set 2: LDC cohorts based upon the identified cost drivers for Support Services, which also involves seven cohort groupings.

3.2 Step 1: Screen and Organize LDC Data

The original data set filed by the LDCs includes 123 data series covering labour quantities (number of employees stated as full time equivalents, or FTEs), labour cost (annual compensation including salaries, wages, and benefits), regional location (EDA district), and the quantities and costs of wholesale electricity purchases. The data set also includes network and business context descriptors such as km of lines, service quantities such as energy consumed and the number of customers, descriptors of the markets served, the presence of control centers, and the types and amounts of the capital employed. As mentioned, these data cover the 2002–2004 experience of the LDCs for costs and services. The data are listed in Tables 3 and 4 of Part I of the Phase II Report, pages 31–35.

Inspection of the data, point by point, reveals errors and omissions in the information provided by the LDCs. The data errors assume several forms: information that appears to represent unobserved experience and approximations, missing data, missing digits to numeric data, and data reported in the wrong reporting fields. Of the 32,964 data points, 362 perceived data errors were discovered, many of which were in data that are essential to the immediate study. Fortunately, many of the data errors were easily corrected through mere inference. As an example, seasonal demand appears, on occasion, to be the sum of the monthly peak demands. Unfortunately, the correction (or resolution) of other errors in the data involved the expenditure of considerable resources to identify and assess anomalous data issues, and to then determine and implement correction methods. The methods for correction include ad hoc approaches, and the application of a general rule as regards to the assignment of labour costs to expense categories. Specifically, the rule assigns labour compensation, as reported, to categories of expenses including operating, billings and collections, and administrative on a pro rata basis, where labour costs are not reported for the respective categories.[6]

3.3 Step 2: Determine Cost Drivers with Econometric Methods

Step 2 identifies the cost drivers that are the basis for grouping Ontario's electric distributors into comparable cohort groups or peers (Step 3 below). The cost drivers appear as cost drivers on the right-hand-side (RHS) of the cost models estimated in the Step 2 analysis. The immediate study uses statistical methods referred to as econometrics to estimate the cost models. The models, as estimated, constitute the estimated the relationships between the costs of the distributors and cost drivers. Once the cost drivers are identified with the models, they can then be used as cluster variables to group the distributors into comparable cohorts.

[6] This correction rule is only relevant for the single equation restricted cost models.

The cost models consist of both single and multiple equation systems. Cost theory provides a basis for the mathematical structure of the equations; econometrics is used to estimate the parameters of the equations. The resulting cost equations reflect the relationships between costs and cost drivers. The equations are *empirical* models because the resulting equations reflect the observed cost and business experience of electric distributors in Ontario.

Nonetheless, the cost estimation process needs a starting point—essentially, a conceptual view of what causal factors determine costs and what the relationship between the factors and costs might be. At the most general level, the relationships between costs and cost drivers for private firms and public organizations are well defined by modern cost theory. Cost theory is stated mathematically, and provides a useful framework for the immediate study.[7] Theory provides a basis for the development of cost equations, which can assume a straightforward, single-equation structure; rather complex equation forms; or systems of multiple equations. As mentioned above, both single equation models as well as a system of equations are used in the Phase II study work.

In addition to a general theoretical framework, cost studies of this kind also need to define plausible factors (cost drivers) that might explain costs differences among electric distributors. Because general cost theory provides no guidance about specific cost factors for electric distribution, such studies typically begin by drawing on the views and opinions of experts. These views constitute experience in the form of general knowledge and intuition about electric distribution services and operations, and how distribution systems are planned and developed. Also, cost studies can draw upon the analysis results of previous studies reported in the formal literature of cost analysis for electric distribution, as well as for other industries.[8] Studies of network industries including telecommunications, pipelines, railroads, airlines, and trucking are useful to review, particularly as regards to the determination and measurement of economies of scale and economies of density. Finally, the exploratory findings of the Phase I work found systematic relationships between costs and key cost

[7] Please reference the Appendix to Part I, Application of Neoclassical Cost Theory.

[8] The immediate study was informed by a number of technical cost studies, as identified in the attached reference list.

drivers. Together, these earlier analyses provide a starting point for the Phase II study work by helping to define candidate cost drivers.

It is perhaps helpful to work through an example. Assume that candidate cost drivers of Operating Expenses (expenses) of Wires and Interconnection Services include km of lines, load density (number of customers/km of lines), number of customers served, and a descriptor referred to as virtual utility status, and that the relationships can be captured in a single equation form. The single equation cost model states that operating expenses—the left-hand-side (LHS) variable is sometimes referred to as the dependent variable, Y_j—are equal to (a function of) cost drivers $i = 1, 2, 3, 4,$ with 1 = km of lines, 2 = load density, 3 = number of customers, and 4 = virtual utility status, which are referred to as the right-hand-side (RHS) variables. These cost drivers determine the operating expenses of LDCs $j = 1, 2, \ldots, n$. Each of these RHS variables, X_{ij}, has a corresponding coefficient, β_i, which represents the effect of cost driver i on operating expenses. The task of econometric methods is to determine the mathematical value of each of the coefficients, given the LHS and RHS variables of the model, along with various supporting diagnostic statistics. The empirical equation to be estimated is as follows:

$$\begin{aligned} \textit{Operating Expenses}_j = {} & B_o + B_1(\textit{km of lines}_j) + B_2(\textit{load density}_j) \\ & + B_3(\textit{number of customers}_j) + B_4(\textit{virtual utility}_j) + E_j\,. \end{aligned}$$

This equation states that the operating expenses of Wires Services for LDC_j ($\textit{Operating Expenses}_j$) are equal to the sum of the product of the estimated coefficients, B_i, and the RHS variables for *LDC j*, plus a model error term, E_j. The error term is the difference between the actual observed value of operating expenses minus the *estimated operating expenses*, $E(Y)$, for LDC_j ($E_j = Y_j - \mathrm{E}(Y_j)$). An error term is present in all models of this type because, by definition, the models inherently do not capture (explain) all differences in the costs among the LDCs. This is a straightforward and readily interpretable outcome: operating expenses are a result of (function of) the product of the RHS variables and the respective coefficients (B_i). Addition across the product of the RHS variables and their coefficients obtains an *estimate* of operating costs for LDC_j; the addition of the product of the RHS variables and their coefficients *plus* the error term (E_j) is the actual, observed operating expenses of LDC_j.

The data set for LDC costs and cost drivers, as used within the econometric analysis, is described by the subscript *j*, and is organized in an array, as follows:

	Costs (Y_i)	$X_{1=\text{km of lines}}$	$X_{2=\text{load density}}$	$X_{3=\text{number of customers}}$	$X_{4=\text{virtual}}$
			RHS Variables (Xij) – Cost Drivers		
${}^{2002}LDC_{j=1}$	*\$23M*	*440*	*52.3*	*23,000*	*1*
			…….		
${}^{2002}LDC_{j=91}$	*\$66M*	*340*	*129.4*	*44,000*	*0*
			…….		
${}^{2003}LDC_{j=1}$	*\$28M*	*455*	*50.9*	*23,140*	*1*

In other words, the LDC data utilized in the econometric analysis are (necessarily) arrayed in a matrix form so that resources, costs, and cost drivers correspond, thus providing a basis for the statistical procedures of econometrics to discern systematic relationships, as captured in the estimated coefficients (*B*s) of the RHS variables. It is useful to mention that the estimated cost equations can have many RHS variables. Indeed, the cost equation of the simultaneous equation restricted cost model, as estimated in the immediate study and presented in Part II, has over 50 RHS variables.

While the opinions of experts and previous studies can help identify cost drivers, the variables used in one study may not work in another study or may not work in the same way. This is particularly true in the case of electric distribution services, where the inherently high correlation among measures of output—energy sales, peak demand, and the number of customers—and various descriptors of distributor systems such km of lines, makes it especially difficult to determine the best set and structural form for the RHS variables as cost drivers. Also, cost drivers can be incorporated into the cost equations in various ways. Accordingly, the Step 2 work involved determining the best combinations of RHS variables as cost drivers. As mentioned, the Phase II work presented here draws upon the opinion of experts and other studies. In various forms and combinations, candidate RHS variables (cost drivers) include (among others): location (northern territory), virtual utility status, share of lines (km) underground, share of facilities (km) 3-phase, number of customers, share of residential customers, ratio of customers/km lines (density), ratio of customers to distribution transformers (density), urban vs. rural territory, energy sales, peak demand, load factor, regional costs, and labour compensation rate.

3.4 Step 3: Determine Cohorts with Clustering Methods

A cohort is a group, where members of the group have common characteristics. The notion of commonality suggests groups of peers organized according to similarity or like features—relevant business context of LDCs in the immediate case. As mentioned above, the cohort groups are based on commonality of cost drivers, as identified by the RHS variables of the cost equations estimated in Step 2. The cohort groups are determined using methods known as statistical clustering.

Systematic grouping of Ontario's distributors is a matter of association, and LDCs can be organized into groups based upon any number of methods, ranging from judgment to formal statistical methods. As an example, LDCs could be organized according to relative size, type of service territory (urban vs. rural), or locale such as northern Ontario as distinct from southern Ontario. Alternatively, several business context variables together could be used to group LDCs. While various ad hoc methods can be both sensible and plausible, such approaches are less than fully objective regarding the manner in which data are managed to obtain the end result, and in the choice of characteristic(s) or variables used as the basis to conduct the grouping.

Statistical clustering can arguably do a better job. Statistical clustering covers a broad range of technical approaches to determine cohorts on a basis of similarity, association, likeness and resemblance of objects of clustering, such as LDCs. While there are a number of alternative statistical clustering methods, the various approaches have a common thread; all would draw upon and discern similarity among business context and other characteristics.[9] The approach applied in the immediate study to determine cohorts is a hierarchical methodology. Hierarchical clustering is an iterative mathematical procedure. For grouping of the LDCs into cohorts, the procedure searches over the data matrix of predefined business

[9] At the broadest interpretation, statistical clustering can cover any measure or metric of association of data including correlation, distance, and probabilistic similarity—e.g., there is a 90% probability that A is like or equivalent to B.

context variables and, first, groups together the two most similar LDCs, given their context variables. The procedure then groups the second most similar LDCs into a third cluster or, possibly, into the first cluster that contains the first two LDCs; and so on.

The number of cohorts is determined beforehand and, for the immediate study, is set at 7 groups. The task of association or grouping by any means, using either statistical clustering methods or other less formal approaches, faces the issue of separable cohorts. As a general rule, the fewer the number of cohorts, the greater the variation within cohorts. This implies that the level of dissimilarity of the electric distributors in any one cohort increases as the number of cohorts decreases. Conversely, the greater the number of cohorts, the less the variation with a corresponding increase in similarity of members of individual cohorts. There is no objective basis to determine the number of cohorts although ad hoc rules and protocols—e.g., that the sum of the squared differences within cohorts must be less than or equal to one half the average of the squared differences across cohorts—can help facilitate the decision regarding the number of cohorts of a clustering study. Such decisions, nonetheless, are a matter of discretion.

The approach to clustering begins with the data set (matrix) of the identified business context variables upon which the LDCs are to be clustered. The context variables used to conduct the clustering and determine cohorts are as follows:

Set 1 Cohorts <u>Wires and Interconnection Services</u>: labour compensation/FTE, electricity sales, kWh/customer, gross assets, customers/km of lines, share of underground lines, virtual utility status, and location in northern territory.

Set 2 Cohorts <u>Support Services</u>: labour compensation/FTE, regional prices, share of residential customers, share of service territory as urban (%), number of customers per km of lines, and virtual utility status.

The cluster variables are normalized prior to applying the hierarchical clustering procedure. Normalization refers to a technical transformation of the data set into a bell curve representation. The result is that each data point for each data series is reflected as the number of standard deviations from the mean value. A normalized data series has a mean of zero. For example, an electric distributor that has, say, a value of +1.0 for the comparator *operating expenses/customer*, is to be interpreted as residing at a level where 16% of its peers within the cohort group have yet higher costs. In other words, the distributor would have fairly high costs with respect to its peers, but not unusually high.

3.5 Step 4: Determine and Report Cost Comparators

Comparators are diagnostic indicators of the relative cost performance of each distributor with respect to the distributors in its cohort, as determined in Step 3 above. The cost comparators are selected on basis of the perceived needs of the Board and Board staff for the purpose of gauging LDC rate applications. The comparators are as follows.

Table 1
Cost Comparators

For Wires Services

CAPITAL ASSETS	EXPENSES
Gross assets/customers	Expenses/Customer
Gross assets/km miles	Expenses/kWh
Gross assets/kWh	Expenses/km lines
Gross assets/kW	Expenses/Gross assets
Distribution Transformers/Customer	FTEs/Customers
Distribution Losses (MWh)/km lines	FTEs/kWh
	Labour Compensation/Customer
	Labour Compensation/kWh
	Labour Compensation/km lines
	Non-Labour Costs/Customer
	Non-Labour Costs/kWh
	Non-Labour Costs/km lines
	Labour Compensation/Expenses
	Non-Labour Costs/Expenses

For Support Services

ASSETS	EXPENSES
Gross assets/customers	Expenses/Customer
Residential customer/total customers	Expenses/Gross assets
	FTEs/Customers
	Labour Compensation/Customer

Non-Labour Costs/Customer
Labour Compensation/Expenses
Non-Labour Costs/Expenses

The above comparators can be augmented with any number of other diagnostic metrics that may be of particular interest to the Board and its staff.

The comparators for the Ontario distributors reflect the latest year for which the relevant data are available. Typically, this is the 2004 experience; however, it can be for an earlier year. The comparators are reported for the cohort groupings of Set 1, Wires and Interconnection Services, and Set 2, Support Services. The comparators are reported as standardized variables for the cohorts. This means that, for each of the comparators, the reported values are the statistical standard deviations of the LDCs' underlying comparator values, with reference to the mean of the comparator for all LDCs in the cohort. Standardization of variables preserves confidentiality and facilitates comparison, where the average value for each cohort is equal to zero. The standardization procedure is discussed more thoroughly in Section 3.0 of Part II of the Phase II Report.

4.0 Distribution Services

4.1 Nature of Distribution Services[10]

Electric distribution covers key functions and activities including transport services (wires and interconnection),[11] billings and collections (settlements), customer services, and administrative support services. Distribution involves the key activities of system operations, operations and maintenance of buildings and associated facilities, and planning to extend the system and to maintain power quality and network reliability.[12] Electricity distributors are linked to meshed and radial transmission networks. These links (load sinks from the perspective of the network) can be a few locations or numerous locations across an entire region.

Distribution wires facilities consist of underground and overhead transformers and conductors organized as mostly radial and loop circuits operated at a variety of voltages.[13] Facilities include right-of-way, towers, conductor, underground conduits, and series and shunt compensation technologies including capacitors, reactors, and static var compensators. Wires facilities also include circuit switch gear and monitoring and control technology known as system control and data acquisition (SCADA) to monitor the process of power delivery in near real time.

The resources employed in distribution include capital recorded as assets, and labour and non-labour inputs including purchased services recorded as operations and maintenance expenses (O&M). Capital employed in wires services includes electrical conductor and

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[10] The first part of this section draws upon the corresponding discussion within the Phase I Report by Christensen Associates Energy Consulting, LLC to the Board, December 2004.

[11] More precisely*, "transport services"* refers to the transport of power from power sources (interconnections with transmission networks) to power sinks (facilities of retail consumers).

[12] The analytical procedures for distribution design and planning involve both the technical aspects and economic considerations (*i.e.,* discounted benefits and costs) of the value of reliability improvement and reduced losses. Assessing the benefits is challenging because numerous candidate expansion plan options may exist, and because of uncertainty regarding the evolution of the relevant region and area over long timeframes. See Willis, H. Lee, *Power Distribution Planning Reference Book*, 1997, Marcel Dekker, Inc.

[13] It is useful to mention that distribution systems can be distinguished as having several configurations including meshed networks, interconnected networks, and link arrangements in addition to open loop and radial lines. See Lakervi, E, Holmes, E. J., *Electricity Distribution Network Design*, 2nd edition, 1995, Peter Peregrinus Ltd. publishers.

connections facilities and equipment, power line trucks and other vehicles, inventory of spare parts of electrical equipment including poles, lines and transformers, and information systems for network control and monitoring; and settlements equipment including meters, bill rendering equipment, and information technology associated with rendering bills, collection of revenue, and customer services.

4.2 Costs of Distribution Services

The direct costs associated with supplying distribution services include operations and maintenance expenses, energy losses, capital charges, and accounting provisions associated with regulation such as regulatory assets and, depending on regulatory jurisdiction, deferred taxes, categories of investment tax credits, customer deposits, allowance for funds used during construction, and contributions in aid of construction. Capital employed in distribution is sizable, and the carrying charges of capital are a substantial share of total costs. The costs used to determine regulated rates are embedded costs, which reflect contemporary O&M expenses, overheads, revenue taxes, and capital charges including return on depreciated assets.

Capital charges include depreciation expenses, property taxes and insurance, income taxes, and rate of return. The rate base usually reflects the vintaged valuation of capital (book costs)—thus the notion of *embedded costs*. Distribution costs used to set rates will likely incorporate certain rate base elements including working capital.

Generally, distribution organizations and companies in North America report cost data organized in a manner that conforms to the Uniform System of Accounts[14] and can provide an accurate reflection of current accounting costs.

4.3 Market Context and Distribution Costs

The distribution systems of the LDCs and the electricity markets that they serve are complicated and can vary substantially. As mentioned, electricity distributors provide

[14] A Uniform System of Accounts was adopted by the Board in its Accounting Procedures Handbook for Electricity Distribution Utilities initially approved in 2000, replacing a different system of accounting used by Ontario Hydro in its prior role as the regulator of the Ontario municipal electricity utilities.

transport services covering a diverse range of business situations.[15] These situations can give rise to substantial differences in total costs, and costs stated on a unit-of-output (or service) basis—*e.g.,* cost per MWh.[16]

It is useful to review the main factors that contribute to costs and cost differences. First, electric distributors serve large- and medium-sized urban areas, municipalities, and rural regions. As a general rule, urban areas give rise to greater load and customer density which tends to reduce average costs because capital and O&M costs per unit of output decline. In contrast, rural areas generally have low density and often reveal fairly high costs, because the amount of conductor and supporting equipment, when stated on a per-customer or peak load basis, is comparatively large.

Second, costs vary with regard to facility configuration, distribution technology, and customer mix. As an example, some distribution organizations may have predominantly secondary facilities, while other organizations may have considerable investment in three-phase primary facilities and associated equipment. Some distributors may have a substantial amount of investment in underground facilities, while others do not. While underground facilities are somewhat more costly, they may be less costly to maintain and may provide improved reliability through reduced frequency of service outages.[17] These differences in the configuration of facilities can reflect mandates of municipalities and differences in design philosophy, in history, and in differences in customer needs which are mostly a matter of the mix of customers served. Design philosophies, methods, and standards may vary and reflect preferences for specific vendor equipment, as distribution crews, over time, become familiar with the attributes and performance of specific equipment.

[15] This study, as well as the previous Phase I work, benefits greatly from CA Energy Consulting's discussions with the Comparators and Cohorts Stakeholder Group during late November 2004.

[16] The output of distribution wires and interconnections service is multi-dimensional, and inadequate definitions of output can confound cost studies. Plausible metrics of the quantity of output—i.e., the *output quantities*—include transport distances such as km and MW-km of lines, peak load (kW) measured as the sum of the non-coincident demands at the transmission interconnection points, the number of customers served, total kVa of transformers at the point of interconnection with consumer facilities, and electricity consumption (kWh).

[17] The outage costs incurred by retail consumers are related to both the frequency and duration of outage events. While underground facilities may reduce the frequency of outages, the duration of outages may be longer because the time required to restore service may be extended due to problems of accessibility.

Third, differences in load growth within existing service territories and the extension of territory have direct impacts on cost differences. Distribution facilities and equipment have exceptionally long lives. For distribution organizations that have little growth over years, the capital base (rate base) may reflect a concentration of early-vintage investment, which tends to reduce costs stated in embedded cost terms. Generally, the maintenance costs of older equipment are higher than those of newer vintage equipment, and there are large differences between the *load-related* marginal costs of wires service and embedded costs of such services, particularly if line extensions are associated with new loads.

Fourth, cost differences will reflect the consolidation of organizations, of distribution functions, and of outsourcing that may have the potential for substantial gains in efficiency due to economies of scale and economies of scope.

In addition to these general considerations, the electric distributors across Ontario have unique attributes relating to service territory and markets. First, the service territory in total is large with numerous large lakes and a range of geography across this vast terrain. In particular, the Canadian Shield covers the area north of an east-west line from Ottawa, which in total constitutes roughly two-thirds of Ontario. This geography can be a rather rough and rocky terrain that, arguably, affects the way that distribution services are planned and constructed where the Canadian Shield rock is exposed or near the surface. The result may be a positive impact on costs vis-à-vis areas of Ontario to the South and Southwest.

Municipalities may impose electricity service requirements that limit the facility choices of LDCs and that are costly. Large urban areas with high load densities may present accessibility constraints for the servicing LDCs that are manifest as higher operating expenses for maintenance.

A number of licensed LDCs described as *virtual utilities* possess distribution assets but outsource all or most of the operating responsibilities to other LDCs or to affiliated or unaffiliated services companies. Finally, it is useful to mention that some LDCs are characterized as *host LDCs*, which provide transport services at subtransmission voltages to other, commonly smaller; utilities described as *embedded LDCs*, in addition to the host LDCs retail customers.

Fifth, the costs of Ontario's numerous distribution organizations are likely to vary because of differences in efficiency of the process of providing distribution services. Relative cost efficiency has investment and O&M dimensions, and some organizations are likely to be highly efficient, while others are less so.

The relative efficiency of Ontario's distributors, after accounting for the relevant factors including business environment, context of distribution facilities, and market context, is of particular interest. Once understood, efficiency, as manifest in the level of cost per unit of output for the defined unbundled services of LDCs, can serve as a mechanism of regulatory governance. This is the reason underlying the C&C study: the Board wishes to gauge and assess the relative costs of individual electric distributors of Ontario with respect to peers, given inherent business context. Accordingly, it is necessary to group the distributors into cohorts of similar context and characteristics.

5.0 Service Definitions and Unbundling

5.1 Unbundled Services

The notion of unbundled services follows from the nature of distribution services. Electricity distribution services can be unbundled into separable functions for purposes of reporting, rate setting, and performance assessment. Moreover, the Uniform System of Accounts as currently structured provides for cost reporting in a manner that facilitates unbundled services. Also, where definable activities are largely independent—e.g., wires services are independent of billings and collections—they would appear to be natural candidates for consolidation and purchased services (outsourcing) in order to achieve scale economies. Separable unbundled services are as follows:

> *Wires and Interconnection:* The reliable transport of electricity from locations where it is received—the interconnection links with transmission facilities—to locations where electricity is consumed by customers.
>
> *Billing and Collections:* the measurement of and billing for electricity service received by customers, which involves meters, meter reading, billing, and revenue collections. Billings and Collections ("B&C") can also include the response to inquiries regarding customer bills, and the collection of delinquent bills. The input costs of B&C include the capital (assets) associated with meters, vehicles, metering and bill rendering equipment, software, and building facilities; and skilled labour and management (which are reported

as direct expenses). Settlement activities may be outsourced or shared services among several LDCs. It is essential that the costs of outsourced activities for billings and collections be reported as Settlements costs.

Customer Service: This third unbundled service category can cover service interruptions, new service connections, service terminations, marketing and promotional activities, and assisting customers in the selection of tariff options,[18] special services such as enhanced quality and insurance products, and consultation regarding energy conservation including energy audits. These activities will likely expand as energy conservation and unbundled electricity services proliferate in the future. Customer services are not currently reported as a separate service by the LDCs, in part because of legislative restrictions on the activities that a regulated distributor can be engaged in. It is likely that some of the functionality and activities of customer services are bundled with and reported as Billings and Collections. The costs of customer services and sales typically involve the capital associated with vehicles, software, and building facilities; and skilled labour and management (which are reported as operating expenses).

Administrative and General Services ("A&G"): These services, sometimes referred to as corporate overheads, are ancillary services that support the direct services provided by distributors. Administrative activities can include accounting, payroll and corporate finance, corporate management, regulatory affairs, management property and liability insurance, legal and legislative affairs, and human resources and the administration of employee benefits. A&G is only indirectly related to the outputs of the direct services including Wires, B&C, and Customer Services. Essentially, the demand for administrative services is a derived demand.[19]

Functional unbundling requires that distributors adhere to strict reporting procedures, as the cost performance of unbundled services cannot be adequately assessed in the absence of appropriate reporting procedures, or where such procedures are not adhered to. Unbundled services and reporting are relevant to the immediate study in two respects. First, not all Ontario distributors provide the full complement of services; it is likely that customer services are of comparatively small scale and implicit in wires and B&C in dissimilar ways across the LDCs. Second, the small size of many of Ontario's LDCs, some of which are

[18] Recent years have evidenced the emergence of a number of new retail products (tariff options) that better align marginal retail prices with economic costs of supply, thus obtaining gains in market efficiency. These options are also geared to achieve a better match of retail pricing design with the needs and preferences of consumers, and can assume a variety of forms that depart substantially from the conventional fixed price-open quantity structure of retail prices. Examples of tariff options include fixed-bill products that hedge price *and* quantity risks, self-designing products, resource portfolio options (green tariffs), critical peak pricing variations of time-of-use, curtailable service with marginal cost-based buy-through provisions, and electronic control-based curtailment of end-uses.

[19] Because administrative costs are true overheads, such costs are assignable to the direct services through cost allocation mechanisms. Studies tend to suggest that overheads are strongly related to the physical capital and expenses including labour and non-labour inputs of unbundled services.

virtual utilities, suggests that the separation of resources and costs for Billings and Collections, and for Administrative and General Services, is unlikely to be a bright line. In particularly, where resources are co-mingled, it is likely that the costs for the identified areas are not reported in a uniform manner by the LDCs. This means that it may be appropriate to merge B&C and AG services for purposes of C&C cost assessment and benchmarking. This is the path selected for the current study. In summary, the immediate C&C study recognizes two unbundled services categories: *Wires and Interconnection Services* and *Support Services* including Billings and Collections plus Administrative and General Services.

6.0 Summary of Study Findings

The implementation of the overall C&C approach as defined by the Board appears to be reasonably successful. A few general observations are as follows:

- The data utilized in the C&C study are remarkably improved from the information available to the Phase I exploratory work. While we continue to find shortcomings in the completeness and accuracy of the data, the data appear to be of sufficient quality to facilitate a successful application of the C&C methodology defined by the Board.[20]

- Strong, systematic relationships exist within the cost, business context, and service level data for the LDCs. As a consequence, formal technical methods of cost analysis can be applied for the purpose of assessing cost performance of Ontario distributors.

- The analysis results, moreover, are reasonably robust and consistent although the problem of high correlation among some RHS variables, particularly for various dimensions of output (customers served, kWh sales, etc.), is often present. Fairly highly correlation of output measures and business context variables are common, with the result that the output variables can be causally related to costs and yet be statistically insignificant or on occasion have the wrong sign in the cost equations.

[20] It is nonetheless appropriate to recognize the potential that a substantial level of error could remain in the data, as utilized in the current study. Such error, should it be of sufficient magnitude, can distort and compromise the analysis results as reported herein.

- Small LDCs appear to have more idiosyncratic cost experience and, in a few instances of the cost equations, fairly large error terms are obtained.

Altogether, four resource and restricted cost equations are estimated as single equation models. These models are complemented by a simultaneous equation system. This latter approach includes a so-called all-in restricted cost model, in addition to the complementary resource share equations. This equation system appears to perform better than the single equation models by all measures. Indeed, the simultaneous equation system obtains, for the restricted cost equation of the three equation system, a substantial improvement in explanatory power, where the R-squared value rises from about 0.9400 to 0.9880, representing a decrease of about 80% in unexplained variation. Similarly, model estimation error of the simultaneous cost model decreases by about two-thirds, when compared to that of the single equation models.

As mentioned, the cost equation of the simultaneous system is also used to determine the level of economies of scale and of density for Ontario distributors. The immediate cost studies find substantial economies over much of service level (output) range.

As demonstrated in Section 3.0 Comparators and Cohorts, of Part II of the Report, high cost experience is easily discerned by the various comparators, which are shown as normalized (standardized) values. The pre-defined comparators are reported for each of the seven cohorts. Set 1 involves the cohorts and comparators for Wires and Interconnection Services, and Set 2 involves Support Services. As discussed in *Part II* of the Report, the Set 1 cohorts are of significant size for 3 of the 7 cohorts for Wires and Interconnection Services, and for 4 of the 7 cohorts for Support Services.

7.0 Concluding Comments

The notion of Comparators and Cohorts set forth by the Ontario Energy Board was recognized as an experimental concept at the outset. The idea of C&C was driven by the magnitude of the task facing the Board and its staff in the 2006 EDR. The C&C methodology, which is a form of cost benchmarking, appeared to offer the potential for substantial efficiency gains in the regulatory process for setting electric distribution rates.

While the overall success of C&C cannot be assessed at this early juncture, we remain guardedly optimistic that this initial study will prove useful to the Board and its staff for the purposes intended.[21]

Nonetheless, we harbor two concerns. First, is the level of detail provided by the C&C analysis, which is geared to determining anomalies in cost performance at a general level, of sufficient depth to satisfy the needs of Board staff for the task at hand? The rate applications of the Ontario distributors will certainly contain unique and idiosyncratic elements, as reflected in the costs at a general level. However, the C&C study provides evidence of these unique aspects only implicitly within the reported results for the general cost categories. Second, does the study present the most appropriate set of Comparators? Specifically, the identified Comparators may not be fully adequate to the needs of staff, and alternative or additional Comparators may be needed. We can expect that the Comparators may change in scope following practical use of this initial C&C study by the Board and its staff, should C&C be developed further.

The cohort groupings have been tested in an ad hoc manner for robustness and consistency of results. While changing the definition of cluster variables alters the cohorts somewhat, the analyses are reasonably stable, as far as cohort groupings are concerned. Nonetheless, alternative approaches to the determination of cohort groups should be explored. While identifying the cluster variables through cost modeling is perhaps the most objective means, the variables used to cluster LDCs into cohorts need not necessarily be obtained from cost models alone.

The C&C methodology, as applied in the Phase II study, provides a foundation to benchmark Ontario distributors in ongoing fashion. While the technical results of the immediate study appear plausible, advances in methodology can obtain improved analysis, should the C&C benchmarking concept be pursued further. Indeed, specific research issues have arisen from this initial exploratory study.

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[21] We wish to acknowledge the substantial contribution by Keith Richie of the Ontario Energy Board staff to the project work. The analyses contained herein could not have been brought to fruition without Keith's guidance and consultation at all levels of the work effort.

An improved and more appropriate metric for capital needs to be developed. The current study has utilized gross assets, an accounting measure, as the metric for physical capital. As discussed at several points in the Phase I report, accounting measures of capital may not adequately reflect the underlying physical resources employed, and future studies should endeavor to develop an alternative capital measure referred to as the real capital stock.[22] Once developed, the real stock metric for capital would be used as the LHS variable for the asset equations, and as a RHS variable in the expenses equations (restricted cost equations).

Second, the single-equation cost models may be improved with second-order terms, or through the application of various flexible form techniques to the LHS and RHS variables other than those applied in the immediate study. Moreover, the equations have not been fully tested for conformity to certain theoretical properties related to econometric models. The results, however, are not necessarily compromised should a violation be present; that is, violation of a condition does not imply bias in model-derived estimates of costs of distributors, although the reliability of the estimated model coefficients may be overstated.

In closing, we wish to comment on the issue of institutional legacy implicit within the cost experience of Ontario distributions, and the implications for cost estimation and interpretation of results. In the immediate context, legacy refers to the underlying market processes and the inherent incentives facing the electricity distributors in Ontario implied by those processes. Ideally, cost estimation would be limited to the incorporation of only input prices and business context variables in the RHS that reflect market conditions and context that reside outside the control of the LDCs, as service providers. However, the Phase II analysis expands the RHS variables beyond this narrow interpretation. That is, the RHS variables include descriptive variables that reflect the ongoing modus operandi—"the way we do things"—as well as the numerous historical decisions of Ontario's distributors regarding the resources employed in the provision of electric distribution services. These decisions are implicit in key RHS variables used in cost estimation and include, for example,

[22] As we mentioned in formal testimony before the Board in January 2005, Docket RP 2004-0188, the historical data series necessary for estimation of the real capital stock are available. However, these data serve only as a starting point, and development of a real stock series for the Ontario distribution would require a substantial amount of data manipulation as well as the construction of output metrics over historical years for use in the determination of an initial real stock. Such an endeavour has been discussed with Board staff, and may be pursued in a follow-up addendum analysis.

share of 3-phase line, share of underground services, km of distribution lines, distribution transformers per km of distribution lines, and the density of customers per distribution transformer.

These variables that describe network characteristics can, in some cases, be interpreted as discretionary variables that essentially reflect the decisions of the distributors regarding resource use. Such decisions affect costs. Moreover, such decisions as implicit in these variables, may not obtain least-cost distribution services for electric consumers. By implicitly accounting for the historical resource choices as a matter of discretion by the distributors in the RHS variables, the cost analysis and results may not be getting at the notion of least cost, as a basis to benchmark the cost performance of Ontario's distributors. In this regard, the current study results can be viewed as somewhat conservative.

The issue of legacy, for purposes of setting rates, is a matter of whether or not and to what degree distributors are to be held responsible for costs as incurred, where such costs may not reflect cost-minimizing behavior and choices historically, given the implicit incentives within the market structure of past eras. Moving forward, we suggest that the Ontario Energy Board: 1) fully consider the cost implications of the incentives implicit in the elements of market structure, as such elements affect the decisions of Ontario's distributors; and 2) where appropriate, incorporate changes to market structure that encourage cost-minimizing behavior and actions by distributors.

Table 2
Distributors In Ontario

NAME	EDA District
Asphodel-Norwood Distribution	Eastern
Atikokan Hydro	Northwestern
Aurora Hydro	Central
Barrie Hydro	Georgian Bay
Bluewater Power	Western
Brant County Power	Niagara Grand
Brantford Power	Niagara Grand
Burlington Hydro	Niagara Grand
Cambridge and North Dumfries Hydro	Niagara Grand
Centre Wellington Hydro	Niagara Grand
Chapleau PUC	Northeastern
Chatham-Kent Hydro	Western
Clinton Power	Niagara Grand
Collus Power	Georgian Bay
Dutton Hydro	Western
Eastern Ontario	Eastern
ELK Energy	Western
Embrun Hydro	Eastern
Enersource Hydro Mississauga	Central
EnWin Powerlines	Western
Erie Thames Powerlines	Western
Espanola Regional Hydro	Northeastern
Essex Powerlines	Western
Festival Hydro	Niagara Grand
Fort Frances Power	Northwestern
Grand Valley Energy	Georgian Bay
Gravenhurst Hydro	Georgian Bay
Great Lakes Power	Northeastern
Greater Sudbury Hydro	Northwestern
Grimsby Power	Niagara Grand

NAME	EDA District
Guelph Hydro	Niagara Grand
Haldimand County Hydro	Niagara Grand
Halton Hills Hydro	Central
Hamilton Hydro	Niagara Grand
Hearst Power	Northeastern
Hydro 2000	Eastern
Hydro Hawkesbury	Eastern
Hydro One Brampton Networks	Central
Hydro Ottawa	Eastern
Hydro Vaughan	Central
Innisfil Hydro	Georgian Bay
Kenora Hydro	Northwestern
Kingston Electricity	Eastern
Kitchener-Wilmot Hydro	Niagara Grand
Lakefield Distribution	Eastern
Lakefront Utilities	Eastern
Lakeland Power	Georgian Bay
London Hydro	Western
Markham Hydro	Central
Middlesex Power	Western
Midland Power	Georgian Bay
Milton Hydro	Central
Newmarket Hydro	Central
Niagara Falls Hydro	Niagara Grand
Niagara-on-the-Lake Hydro	Niagara Grand
Norfolk Power	Niagara Grand
North Bay Hydro	Northeastern
Northern Ontario Wires	Northeastern
Oakville Hydro	Central
Orangeville Hydro	Georgian Bay
Orillia Power	Georgian Bay
Oshawa PUC Networks	Eastern
Ottawa River Power	Eastern

NAME	EDA District
Parry Sound Power	Georgian Bay
PenWest Utilities	Niagara Grand
Peterborough Distribution	Eastern
Port Colborne Hydro	Niagara Grand
PowerStream	Central
PUC Distribution	Northeastern
Renfrew Hydro	Eastern
Richmond Hill Hydro	Central
Rideau St. Lawrence	Eastern
Scugog Hydro	Central
Sioux Lookout Hydro	Northwestern
St. Catharines Hydro	Niagara Grand
St. Thomas Energy	Western
Tay Hydro	Georgian Bay
Terrace Bay Superior Wires	Northwestern
Thunder Bay Hydro	Northwestern
Tillsonburg Hydro	Western
Toronto Hydro	Central
Veridian Connections	Central
Wasaga Distribution	Georgian Bay
Waterloo North Hydro	Niagara Grand
Welland Hydro	Niagara Grand
Wellington Electric Distribution	Niagara Grand
Wellington North Power	Georgian Bay
West Coast Huron	Niagara Grand
West Nipissing	Northeastern
West Perth Power	Niagara Grand
Whitby Hydro	Eastern
Woodstock Hydro	Western

Table 3
PBR Data Series

<u>**PBR Data Series, Ontario Distributors**</u>

Labour Inputs and Costs

Full-time employees
Part-time employees
Full-time equivalents
Virtual LDC, an identification variable
Outsourcing, an identification variable
Wage compensation to employees
Salary compensation to employees
Fringe benefits to employees
Jan_1_05 wage rate for employees
Change date of wage rates for employees
New wage rate for employees

Current Capital Expenditures and Assets

Capitalized labour within capital accounts
Gross fixed assets
Net fixed assets
Accounting depreciation
Accounting amortization
Total capital additions
Capitalized labour within capital additions
Capitalized overhead within capital additions
Capitalized equipment in capital additions
Other capitalized costs in capital additions
Capital retirements
Contributed capital
1995 – Contributions and Grants - Credit

Annual Expenses

Total operating expenses, wires services
Labour costs within operating expenses, wires services
Total billings and collections expenses
Labour costs within billings and collections expenses
Total administrative and general
expenses
Labour costs within administrative and general expenses
Total Expenses

Wholesale Purchases and Retail Markets

Wholesale cost of power
Wholesale electricity purchases (MWh)
Electricity consumption (MWh)
Distribution line losses (MWh)
Total customers
Total customers without street lighting and sentinel
Residential customers
General service customers
Large usage customers
Streetlighting connections
Sentinel lighting customers
Total electricity sales (kWh)
Residential electricity sales (kWh)
General service electricity sales (kWh)
Large usage customers' electricity sales (kWh)
Streetlighting electricity sales (kWh)
Sentinel lighting electricity sales (kWh)
Total kW to customers, as billed
Billed kW to residential customers
Billed kW to general service customers
Billed kW to large usage customers
Billed (estimated) kW for streetlighting
Billed kW for sentinel lighting
Seasonal customers
Winter maximum peak load
Summer maximum peak load

Annual Revenues

Annual total revenues
Annual residential revenues
Annual general service revenues
Annual large-usage revenues
Annual streetlighting revenues
Annual sentinel lighting revenues

Service Area Context

Total square kilometers of service area
Rural square kilometers of service area
Urban square kilometers of service area
Service area population

Municipal population

Network (Technology) Descriptors

Total kilometers of line in the service area
Kilometers of overhead lines within the service area
Kilometers of underground lines in the service area
Kilometers of 3-phase service in the service area
Kilometers of 2-phase lines in the service area
Kilometers of single phase lines in the service area
Number of transmission transformers
Number of sub transmission transformers
Number of distribution transformers
Customers per Dx Transformer
Northern Ontario (a descriptor variable)
EDA District (a descriptor variable)
Voltage levels (kV) of the distribution system (a basis for potential descriptor variables)
Number of substations
Presence of control centre functionality (a basis for potential descriptor variables)
Presence of transmission system facilities (a basis for potential descriptor variables)
Special circumstances (a basis for potential descriptor variables)

Table 4
Trial Balance Data Series

Trial Balance Capital Accounts, Ontario Distributors

1805 - Land
1806 - Land Rights
1808 - Buildings and Fixtures
1810 - Leasehold Improvements
1815 - Transformer Station Equipment - Normally Primary above 50 kV
1820 - Distribution Station Equipment - Normally Primary below 50 kV
1825 - Storage Battery Equipment
1830 - Poles, Towers and Fixtures
1835 - Overhead Conductors and Devices
1840 - Underground Conduit
1845 - Underground Conductors and Devices
1850 - Line Transformers
1855 - Services
1860 - Meters
1865 - Other Installations on Customers? Premises
1870 - Leased Property on Customer Premises
1875 - Street Lighting and Signal Systems
1905 - Land
1906 - Land Rights
1908 - Buildings and Fixtures
1910 - Leasehold Improvements
1915 - Office Furniture and Equipment
1920 - Computer Equipment – Hardware
1925 - Computer Software
1930 - Transportation Equipment
1935 - Stores Equipment
1940 - Tools, Shop and Garage Equipment
1945 - Measurement and Testing Equipment
1950 - Power Operated Equipment
1955 - Communication Equipment
1960 - Miscellaneous Equipment
1965 - Water Heater Rental Units
1970 - Load Management Controls - Customer Premises
1975 - Load Management Controls - Utility Premises
1980 - System Supervisory Equipment

1985 - Sentinel Lighting Rental Units
1990 - Other Tangible Property
1995 - Contributions and Grants – Credit

APPENDIX to PART I

APPLICATION OF NEOCLASSICAL COST THEORY

Underlying Theory

Theory is a conceptual design that explains phenomena and behavior. In the immediate context, the relevant theory is economic cost theory about how LDCs select inputs for employment in the process of providing electric distribution services. Economic theory, or a statement of theory, provides a useful starting point for the C&C analysis by offering:

- A framework of the production and cost behavior of the firm, which is a means to determine how to structure analysis.
- A foundation for how to organize data for use in cost analysis. Theory provides a basis to address the question: what is it that determines costs?
- A basis for the interpretation of data, analysis results, and the formation of inferences about LDC cost performance.

The theory begins with the commonly held understanding that the firm employs resource inputs in order to satisfy the demand for its services.[23] The choice of resource bundle—resource combination—is an issue of process and cost efficiency, and the firm can often select a range of possible production processes. Resource inputs are costly and, optimally, the firm would choose the least-cost bundle of resources that satisfy demand, given the prices of inputs.

The resource choice problem facing the firm can be described as a cost minimization problem, given the business and market environment in which the firm operates. At a general level, the problem can be stated as involving four variables:

Input Prices (*W*)	= factor input prices for the resources employed by the firm
Output Prices (*P*)	= prices that the firm charges for its services (outputs)
Outputs (*Y*)	= quantities of output supplied by the firm in service of the demands for its services
Inputs (*Q*)	= quantities of input employed by the firm in the process of providing output.

[23] The start of this discussion is largely—though not exclusively—taken from the relevant section of the Phase I report to the Board by Christensen Associates Energy Consulting, LLC.

The total cost of providing service can be stated as:

$$\Sigma\, Q_j * W_j = Cost = C\,(Y_i \ldots Y_I;\; W_j \ldots W_J;\; Z_m \ldots Z_M)\ .$$

The set of variables, *Z*, define the set of factors that describe the firm's business and market context. Within the context of electric distribution, the *Z* factors can include load density, load factor, the presence of an urban service territory, service specifications and mandates of municipalities, etc.

Presumably, the vector of output prices, *P*, is set by the regulators at a level such that total costs are recovered—*i.e.,* $P*Y = W*Q$. Essentially, the regulators set the prices, *P*, which in turn determine the level of output, *Y*—*i.e.,* the level of consumer demand. Thus, the level of output becomes exogenous to the firm. Conditional on output, *Y*, along with the price of inputs, *W*, and the conditions of the business environment, *Z*, the firm selects the least-cost combination of inputs, *Q*.

The problem facing the firm, then, can be cast as an issue of minimizing costs, given exogenous demand for output and input prices (*Y*, *W*) and the business and market environment, *Z*. Quantities of output, input prices, and the business context are exogenous to and outside the control of the management of the firm. The firm can choose the quantities of the input factors, *Q*, subject to the constraints of the production process (that demands are satisfied) and conditions of the business environment. Optimally, the firm will utilize each input factor, Q_j, up to the point where the value of its marginal product is equal to the input price, W_j.

We can view this problem a little differently for purposes of cost assessment. That is, costs can be stated on a *unit cost* basis,

$$\Sigma\, Q_j * W_j / Y = (W_j \ldots W_J;\; Z_m \ldots Z_M)$$

where the unit cost, $\Sigma\, Q_j * W_j / Y$, is a function of input prices and the various factors that identify and capture elements of the business environment of the firm, Z.

This highly generalized discussion can be pursued further, and it is useful to begin with recognition of the fundamental categories of inputs including *capital*, *labour*, *materials*, and *energy*. The quantity measures of each reflect the flow of services each input provides to production. For capital input, this means that each vintage—e.g., capital additions in, say, 1983, 1984, etc.—should be weighted by its relative contribution or productivity.

In the following discussion, the quantities of capital, labour, quasi-materials and purchased services ("quasi-materials"), and energy are denoted as Q_K, Q_L, Q_M, and Q_E, respectively. The corresponding prices of capital, labour, quasi-materials, and energy inputs can be denoted as P_K, P_L, P_M, and P_E, respectively. The discussion can also consider aggregates of the variable inputs of the firm including *labour*, *quasi-material, and service inputs*—generally referred to as operating expenses—and *energy*. Further, the discussion can denote the aggregate quantity of inputs of operating expense by Q_X and the aggregate price of the variable inputs as P_X. Operating expense (the cost of labour, quasi-materials, and energy) will be denoted C_X. Finally, total cost, C_T, can be defined as the sum of the costs of capital, labour, quasi-materials, and energy or, equivalently, capital cost plus operating expense.

The *total cost function* relates total cost to the prices of the inputs, the quantities of output, and exogenous conditions referred to as, in the immediate context, business context variables. The total cost function then has the form:

$$C_T = C_T\left(P_K, P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j\right).$$

The total cost function is homogeneous of degree one in the input prices. That is, doubling input prices doubles total cost. Shepherd's Lemma states that the factor demand equations for Q_K, Q_L, Q_M, and Q_E can be obtained by differentiating the total cost function with respect to the input prices. For example the demand for the quantity of capital services can be obtained by differentiating the total cost function with respect to the input prices.

$$Q_K = \frac{\partial C_T}{\partial P_K} = Q_K\left(P_K, P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j\right).$$

The demand equation is homogeneous of degree zero in the input prices.

A *restricted cost function* relates *operating expenses*, including all variable costs—labour (L), quasi-materials (M), and energy (E)—to the prices for the respective inputs; to the quantities of output; to exogenous conditions (business context); and to the quantity of capital. The restricted cost function has the form:

$$C_X = C_X\left(P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right).$$

The restricted cost function is homogeneous of degree one in the prices of labour, materials, and energy. Shepherd's Lemma can be applied to the restricted cost function to obtain (restricted) the demand for the general inputs of labour, materials and purchased services, and energy, and is of the form:[24]

$$Q_L = \frac{\partial C_X}{\partial P_L} = \widetilde{Q}_L\left(P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right),$$

$$Q_M = \frac{\partial C_X}{\partial P_M} = \widetilde{Q}_M\left(P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right), \text{ and}$$

$$Q_E = \frac{\partial C_X}{\partial P_E} = \widetilde{Q}_E\left(P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right).$$

By aggregating labour, quasi-materials, and energy together, an alternative specification of the restricted cost function (which is implicitly a restricted demand equation for the aggregate of labour, quasi-materials, and energy) can be obtained.

$$C_X = C_X\left(P_X, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right) = Q_X\left(Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right) \cdot P_X .$$

This argument is true due to linear homogeneity in the prices of labour, materials, and energy.

Estimation Approach: Restricted Cost Functions and Resource Shares

As a matter of empirical estimation, the approach taken is to: 1) define operating expense as a restricted cost function, estimated as a system of equations that includes the cost shares for input arguments, and as single equations in the arguments; and 2) to define capital as a demand function for capital, estimated with a single equation regression model. For the all-in variable costs, the restricted model structure to be estimated as a simultaneous system is as follows:

[24] Resource demand equations are sometimes referred to as share equations.

$$
\begin{aligned}
C_{OM} &= \left(P_L, P_M, P_E, Y_1, \ldots, Y_n, Z_1, \ldots Z_m\right) \\
\frac{\partial C_{OM}}{\partial P_L} &= \left(P_L, P_M, P_E, Y_1, \ldots, Y_n, Z_1, \ldots Z_m\right) \\
\frac{\partial C_{OM}}{\partial P_M} &= \left(P_L, P_M, P_E, Y_1, \ldots, Y_n, Z_1, \ldots Z_m\right) \\
\frac{\partial C_{OM}}{\partial P_E} &= \left(P_L, P_M, P_E, Y_1, \ldots, Y_n, Z_1, \ldots Z_m\right).
\end{aligned}
$$

In keeping with the previous discussion, the arguments that explain total variable costs (C_{OM})—i.e., right hand side variables—include the prices of the inputs (P_L, P_M, and P_E), measures of the output of services provided ($Y_1, \ldots, Y_n$), business context variables ($Z_1, \ldots, Z_m$), and capital, K. This is just as before; the innovation is the recognition that the restricted cost function and demand for resource inputs (share equations) can be determined as a system of simultaneous equations.

Equation Forms

As shown above, the demand for capital inputs, Q_K, includes the following general arguments:

$$
Q_K = \left(P_K, P_L, P_M, P_E, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j\right)
$$

and can be estimated as single equation models using ordinary least squares (OLS) procedures or with more complex yet flexible functional forms, such as the translog form discussed below. In such case, it is necessary to specify the left hand side (LHS) and right hand side (RHS) variables. The LHS variable, often referred to as the dependent variable, in the above equation would be a quantity of input, such as an amount of capital measured in asset dollar terms. The RHS would be a set of explanatory variables that, together, explain the differences in the dependent variable (the LHS).

In the above, the LHS variable (quantity of input) is *explained* by RHS variables. This means that the differences among—or variation across—the quantities of an input class, such as a type of capital resources, for firms that provide services or products can be determined *or explained* by a pre-defined or derived set of factors. Whether or not pre-defined RHS variables in fact explain variation in observed LHS variable is an empirical matter, which essentially constitutes a testable hypothesis.

A plausible hypothesis of how the quantity of inputs is determined is set forth by the above cost theory. This general theory, neoclassical cost theory, is applied in the immediate study. Thus, as a starting point, it is both reasonable and appropriate to suggest that the costs of Ontario's LDCs are explained by RHS variables including input prices (P_K, P_L, P_M, and P_E) such as labour wages and other compensation to employees of the service providers (LDCs); quantities of output (Y) such as kilometers of lines or numbers of customers served as a measure of transport services provided; and a set of business context variables (Z_j) such as kilometers of lines, the share of underground lines, customer density metrics, and potentially a host of other factors.

The equation relating the LHS to the RHS variables can be solved using well-known statistical methods such as ordinary least squares (OLS) procedures. The procedures obtain (solve for) coefficients for each of the RHS variables, and also provide diagnostic information that provides a basis to assess the strength of the underlying relationships. Similarly, the restricted cost function,

$$C_X = C_X\left(P_X, Y_1, \ldots, Y_l, Z_1, \ldots, Z_j, Q_K\right)$$

can also be estimated as a single equation model structure with conventional OLS methods.

In order to implement empirically the theory described in the previous paragraphs, one must choose a functional form for the cost equations. Functional form can be a simple linear structure, single or double log structures, or other more flexible forms involving higher-order terms such as the Box-Cox transformation, or the translog structure.

The translog structure is used herein in the case of the restricted cost function estimated as a simultaneous system. A translog model, which is an application of a Taylor series expansion, is particularly attractive since it provides a substantial degree of flexibility in estimation. The translog total cost function uses logarithmic values of cost, prices, outputs, and network and market context variables, as follows:

$$
\begin{aligned}
\ln(C_T) = \alpha_0 &+ \sum_i \alpha_i \cdot \ln(P_i) + \sum_i \beta_i \cdot \ln(Y_i) + \sum_i \delta_i \cdot \ln(Z_i) \\
&+ .5 \cdot \sum_{i,j} \alpha_{ij} \cdot \ln(P_i) \cdot \ln(P_j) + .5 \cdot \sum_{i,j} \beta_{ij} \cdot \ln(Y_i) \cdot \ln(Y_j) \\
&+ .5 \cdot \sum_{i,j} \delta_{ij} \cdot \ln(Z_i) \cdot \ln(Z_j) + \sum_{i,j} \phi_{ij} \cdot \ln(P_i) \cdot \ln(Y_j) \\
&+ \sum_{i,j} \varphi_{ij} \cdot \ln(P_i) \cdot \ln(Z_j) + \sum_{i,j} \gamma_{ij} \cdot \ln(Y_i) \cdot \ln(Z_j).
\end{aligned}
$$

The parameters $\alpha, \beta, \delta, \phi, \varphi,$ and γ are unknowns, and are thus to be estimated econometrically. One can apply Shepherd's Lemma to the translog total cost function to obtain cost share equations for the inputs:

$$
s_i = \frac{P_i \cdot Q_i}{C_T} = \alpha_i + \sum_j \alpha_{ij} \cdot \ln(P_j) + \sum_j \phi_{ij} \cdot \ln(Y_j) + \sum_j \varphi_{ij} \cdot \ln(Z_j).
$$

The translog total cost function can be determined by combining the share equations for the inputs with the translog total cost function, and then estimating them simultaneously using Zellner's seemingly unrelated regression approach. Because the share equations exactly sum to one in each observation, one of the equations must be deleted before estimation. Iteration of the Zellner estimator until reaching a converged solution ensures that the results are invariant to the share equation not explicitly represented in the result.

The translog restricted cost function has a similar form:

$$
\begin{aligned}
\ln(C_x) = \alpha_0 &+ \sum_i \alpha_i \cdot \ln(P_i) + \sum_i \beta_i \cdot \ln(Y_i) + \sum_i \delta_i \cdot \ln(Z_i) + \delta_K \cdot \ln(Q_K) \\
&+ .5 \cdot \sum_{i,j} \alpha_{ij} \cdot \ln(P_i) \cdot \ln(P_j) + .5 \cdot \sum_{i,j} \beta_{ij} \cdot \ln(Y_i) \cdot \ln(Y_j) \\
&+ .5 \cdot \sum_{i,j} \delta_{ij} \cdot \ln(Z_i) \cdot \ln(Z_j) + .5 \cdot \delta_{KK} \cdot \ln(Q_K) \cdot \ln(Q_K) \\
&+ \sum_{i,j} \phi_{ij} \cdot \ln(P_i) \cdot \ln(Y_j) + \sum_{i,j} \varphi_{ij} \cdot \ln(P_i) \cdot \ln(Z_j) + \sum_i \varphi_{iK} \cdot \ln(P_i) \cdot \ln(Q_K) \\
&+ \sum_{i,j} \gamma_{ij} \cdot \ln(Y_i) \cdot \ln(Z_j) + \sum_i \gamma_{iK} \cdot \ln(Y_i) \cdot \ln(Q_K) + \sum_i \delta_{iK} \cdot \ln(Z_i) \cdot \ln(Q_K).
\end{aligned}
$$

One should note that the price terms refer to the variable inputs only, as the quasi-fixed input capital is represented by its quantity. One can apply Shepherd's Lemma to the translog restricted cost function to obtain share equations of the variable inputs, as shares of restricted cost.

$$s_i = \frac{P_i \cdot Q_i}{C_X} = \alpha_i + \sum_j \alpha_{ij} \cdot \ln(P_j) + \sum_j \phi_{ij} \cdot \ln(Y_j) + \sum_j \varphi_{ij} \cdot \ln(Z_j) + \varphi_{iK} \cdot \ln(Q_K).$$

As with the translog total cost function, the translog restricted cost function and the accompanying share equations can be estimated as a system using simultaneous estimation procedures such as the iterative Zellner estimator.

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PHASE II REPORT

PART II
EMPIRICAL ANALYSIS AND RESULTS:
COMPARATORS AND COHORTS STUDY FOR 2006 EDR

for the consideration of:

The Ontario Energy Board and Staff

by:

Robert Camfield

J. David Glyer, PhD

Philip Schoech, PhD

Michael Welsh, PhD

Christensen Associates Energy Consulting, LLC

October 2005

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1.0 Introduction to Empirical Analysis

As discussed in section 3 of Part I of the Report, the Comparators & Cohorts (C&C) analysis involves a four-step process. Following Step 1, *screen and organize data*, the process proceeds by *determining cost drivers with econometrics* (Step 2), *determining cohorts* (Step 3), and then concludes by *determining and reporting cost comparators* (Step 4). Steps 2–4 essentially constitute the empirical analysis of the study, as follows:

Step 2, determine cost drivers with econometrics. The cost drivers, including business context variables (e.g., share of underground facilities), are identified with resource and cost models, as estimated with econometric methods. *Single equation models* are estimated for:

- *Factor demand equations* (resource models) for the capital assets used in providing wires and interconnection services, and support services. Of the numerous equations estimated, two equations are reported.

- *Restricted cost equations* (cost models) for expenses (variable costs) incurred in wires and interconnection services, and support services. Two equations are reported.

In addition, a *simultaneous equation system* is estimated for the restricted cost function for all-in variable costs (expenses). This equation system covers the variable costs for wires and interconnection services, billings and collections, administrative and general expenses, and the costs of energy losses; and the complementary share equations for labour resources, for energy costs (distribution losses), and (implicitly) for non-labour inputs.

<u>Step 3, determine cohorts</u>. The assignment of distributors to cohorts is based on cost drivers identified as variables in the resource and cost models in Step 2. As discussed in Section 3 of Part I, LDCs are assigned to cohorts with a hierarchical clustering methodology, where the distributors are grouped into seven cohorts.

The cluster analysis is performed separately for Wires and Interconnection Services and Support Services, which results in two corresponding sets of cohorts (seven cohorts for each of the two services).[1] The clustering methodology is applied to the observed values (normalized) of the selected cluster variables, not the log of the values. The LDC composition among the cohorts are markedly similar had the cluster analysis been applied to the log of the values.

<u>Step 4, determine and report cost comparators.</u> The final step is the reporting of the pre-defined comparators for each of the distributors. As discussed, the comparators are diagnostic indicators of the relative cost performance of each distributor with reference to the average for all distributors in its cohort. Comparators are reported as standardized variables. This means that, for each of the comparators, the reported value for an LDC is the statistical standard deviation of the underlying value with reference to the average of the comparator values for all LDCs in the cohort. The comparators reflect the 2004 experience of the LDCs.

2.0 Empirical Cost Models

2.1 Single Equation Models

As discussed elsewhere in the report, resource inputs (capital assets) and variable costs (costs reflected as expenses) are a function of the level of output, input prices, and business context attributes. The output, input price, and business context variables are described as follows:

- *<u>output variables</u>* utilized as explanatory variables in the resource and cost models (referred to as right-hand-side variables or RHS variables) include *kW*km of lines*, *MWh sales*, and *number of customers*.

[1] As mentioned earlier, *Support Services* includes the resources and costs of the categories referred to as *Billings and Collections* and *Administrative and General*.

- <u>*input price variables*</u> used in the models include *labour costs* which are measured as compensation per full time equivalent (c*ompt/FTE*); and *regional prices*, which is the weighted average labour compensation paid by the LDCs in the relevant region.[2, 3]
- <u>*business context variables*</u> utilized in the models include *share of underground lines*, *share of 3-phase lines*, *share of urban area*, *customers per km of lines*, *share of residential customers to total customers*, *virtual utility status,* and *northern territory*.[4]

The capital assets variable, *gross assets*, is incorporated into the RHS of the restricted cost equations for Wires and Interconnection Services (equation 2) and Support Services (equation 4). All four equations are estimated in *double log*, which means that all variables (LHS and RHS) are in natural log form. This approach has two main advantages. First, the conversion of the data for the LDCs to log form dramatically compresses the scale of the data. Insofar as the electric distributors of Ontario vary greatly in size—roughly four orders of magnitude—log form greatly mitigates the effects of scale. Second, the coefficients associated with log variables are estimates of the underlying elasticity, where elasticity of a RHS variable is the percentage change in the LHS variable—i.e., capital assets or expense costs—with respect to a one percent change in the variable, holding other RHS variables constant.

The estimated single equation models of capital assets and expenses (variable costs) for Wires and Interconnection Services are as follows:

---

[2] The pattern of labour compensation among regions follows, as a general rule, the relative price level for goods and services. Hence, labour compensation can be used as a surrogate for overall regional price differences. Accordingly, we can expect the general price level to be lower in rural and remote areas of Ontario than in the urban areas of southern Ontario, and that such differences will be reflected in labour compensation per FTE for the LDCs of the regions.

[3] It is conceivable that capital costs, characterized as cost per unit of physical capital employed, could also be introduced into the RHS as an input price variable if: 1) there was reason that capital costs would be sufficiently differentiated across the Ontario distributors, and 2) capital costs per unit of input was revealed as an observable or implied data series.

[4] The Northern location is utilized as a binary "shift" variable. However, the Virtual Utility variable, which is also a binary variable type, interacts with labour compensation and input quantities and, for the simultaneous equation system, plays an important role in the share equations as well as the restricted cost equation.

Table 1

Equation 1: Capital Resources (Gross Assets) Employed In Wires Services

RHS Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-Value
Compensation/FTE	0.1278	0.1541	0.83
kW*km Lines	0.5249	0.0127	41.25
Regional Prices	0.5998	0.3612	1.66
Share Underground Lines	0.0833	0.0310	2.69
Share 3-Phase Lines	0.2756	0.0852	3.23
Northern Territory	0.0763	0.0832	0.92

Summary Statistic	Value
Number of observations	255
F(7, 247)	622
Prob > F	0.0000
Adj R-Squared	0.936
RMSE	0.4292

Table 2

Equation 2: Expenses (Variable Costs) Associated With Wires Services

RHS Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-Value
Compensation/FTE	0.0188	0.1377	0.14
MWh Sales	0.6180	0.0536	11.53
Assets, Wires Services	0.3672	0.0492	7.47
Regional Prices	-0.5582	0.2930	-1.91
Share Urban Area	-0.0837	0.0264	-3.17
Share Underground Lines	-0.1313	0.0266	-4.93
Virtual Utility Status	0.1372	0.0790	1.74

Summary Statistic	Value
Number of observations	260
F(8, 251)	813
Prob > F	0.0000
Adj R-Squared	0.962
RMSE	0.263

The estimated models for Wires and Interconnection Services are highly significant, as suggested by the F test results, where the obtained values are substantial, along with the corresponding value for Prob > F = 0.0. Also, the values of the adjusted R-squared statistic of over 0.90 suggest acceptable explanatory power, where R-squared refers to the percentage of the sum of the squares of the LHS variable (capital assets, and expense costs) explained by the RHS variables of the respective equations. *Root Mean Square Error*, referred to as RMSE, is the square root of the average of the square of the error terms of the observations of the LHS variables. The reported RMSE values are of modest size suggesting that, on average, the estimated equations are capturing much of the variation in the capital assets and expenses for Wires and Interconnection Services. While the mathematical sign of the coefficients for the variables generally conform to expectations, there are exceptions and it is perhaps useful to review the equations and comment on the individual variables of the estimated equations.

<u>*Capital Resources Model (Equation 1).*</u> In the case of capital, as an input resource, theory and experience leads to the expectation that capital assets is a substitute input for labour and other inputs.[5] While this is not always the case—capital can complement some resource bundles—the employment of capital assets would likely increase as labour costs (*comp/FTE*) and regional prices increases, and thus the sign of the coefficients for *comp/FTE* and *regional prices* would be positive, which is the case as shown in Table 1, although *comp/FTE* is of very low statistical significance. Also, intuition suggests that the employment of capital

[5] Other inputs are sometimes referred to quasi-material inputs, and can involve materials, purchased services and various inputs other than labour and capital.

increases with an increase in the level of Wires and Interconnection Services provided. For the Capital Resources equation for Wires, output is reflected by the RHS variable, *kW*km lines*. As expected, a positive relationship between capital and output is confirmed, as the coefficient for *kW*km lines* is highly significant. However, the course of the project work involved estimation of alternative output variables, and other specifications of output were found to also be viable, which is not surprising as output metrics are highly collinear.

The estimated coefficients of the remaining RHS variables for the capital resources model for Wires—*share underground lines, share 3-phase lines*, and *northern territory*—have the anticipated signs. That is, underground lines involve a more intensive utilization of capital resources than overhead facilities, other factors constant. Similarly, 3-phase facilities are more costly than single- and two-phase facilities. Moreover, the analysis suggests that distribution service in Ontario's Northern Territory involves a more intensive use of capital, although the statistical relationship, as shown by the comparatively low t-value, appears to be relatively weak.

<u>*Expenses (Equation 2).*</u> Turning to expenses for Wires and Interconnection Services as reported in Table 2, the estimated model (restricted cost model) consists of 7 RHS variables including input prices, output, assets, and business context types of variables. While the overall model performance is acceptable, the several individual variables conform to expectations. Specifically, the level of expenses rises with increased output, as reflected by the variable, *MWh sales*, and declines with respect to increases in the share of service territory that is urban (*share urban area*). As expected, the level of expenses declines as the *share of underground lines* increases.

In some cases, however, variables are either insignificant at conventional levels of confidence or have inconsistent or implausible mathematical sign. The analysis indicates that the RHS variable *virtual utility status* tends to increase the level of operating expenses, which suggests that the reduced costs for direct labour, as implied, are not sufficient to cause the overall level of expenses to decrease, other factors held constant.[6] The variables referred to as *regional prices* and *wires capital* appear to have the wrong theoretical sign, and are significant and of fairly high elasticity.[7] This alone is not too problematic, as it is common for the coefficients attending quasi-fixed inputs—in this case, capital assets associated with wires services—to have the wrong sign**.** This intuitively inconsistent relationship between expenses and capital assets was also found to be present in Support Services and the restricted cost equation of the simultaneous cost system, as discussed below.

The single equation models for gross assets and expenses for Support Services are as follows:

Table 3

Equation 3: Capital Resources (Gross Assets) Employed In Support Services

RHS Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-Value
Number of Customers	1.1126	0.0298	37.31
Compensation/FTE	0.2839	0.1786	1.59
Customer/km of Lines	-0.2925	0.0636	-4.60
Virtual utility status	-0.8758	0.0984	-8.90
Northern territory	0.2639	0.0883	2.99

[6] A concern regarding the sign for virtual utility is consistency in the reporting of data. Also, virtual utility status may suggest unusual circumstances where it is not readily possible to substitute between internal resources and outsourced services. Where distributors are captive, the variable virtual utility status may be capturing the exercise of market power by suppliers where such services are not procured competitively. Also, the procured services may assume a bundled form that is not well tailored to the particular needs for services of the distributor.

[7] Where the cost models are estimated in double log form, the coefficients of the RHS variables are also elasticities. For the capital assets variable, the value of the coefficient implies a 0.37 percent change in operating expenses resulting from a one percent change in capital assets.

Summary Statistic	Value
Number of observations	261
F(5, 255)	620
Prob > F	0.0000
Adj R-Squared	0.923
RMSE	0.508

Table 4

Equation 4: Expenses (Variable Costs) Associated With Support Services

RHS Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-Value
Assets, Support Services	0.0310	0.0320	0.97
Compensation/FTE	-0.0776	0.0934	-0.83
Regional Prices	0.6747	0.1952	3.46
Number of Customers	0.8476	0.0382	22.21
Share Urban Area	0.0190	0.0201	0.94
Share Residential_Customers	-1.0504	0.6103	-1.72
Customer Density	-0.2187	0.0404	-5.41
Virtual Utility Status	-0.0207	0.0582	-0.36

Summary Statistic	Value
Number of observations	260
F(8, 251)	813
Prob > F	0.000
Adj R-Squared	0.962
RMSE	0.263

As mentioned earlier, the LHS variables of the capital resources (Equation 3) and expenses (Equation 4) models for Support Services cover the functions referred to as Billings and Collections and Administrative and General categories. As with the models for Wires, these models reveal fairly high test results for statistical significance and acceptable explanatory power. The signs on the estimated coefficients of the RHS are generally plausible, although there are exceptions, as was discovered in the cost analysis for Wires and Interconnection Services.

<u>Capital Resources (Equation 3).</u> As shown in Table 3, the capital resources (gross assets) model consists of five RHS variables. All variables are statistically significant and of the anticipated sign. The variable *number of customers* is incorporated into the RHS as the output variable with high explanatory power. The coefficient of the input cost variable, compensation/FTE, carries the anticipated sign though with fairly low significance. The three business context variables including *customers/km of lines, virtual utility status*, and *northern territory* perform as anticipated.

<u>Expenses (Equation 4).</u> This restricted cost model for Support Services, as shown in Table 4, consists of eight RHS variables, with *number of customers* incorporated as the measure of output. Input prices including *comp/FTE* and *regional prices* are insignificant in the case of the price of labour, and significant and with the correct sign in the case of *regional prices*.[8] One of these variables could be excluded from the equation; however, because the coefficients (elasticities) are small, exclusion would have little overall impact. As before, capital resources appear in the equation with the incorrect sign.

The remaining four variables, including *share urban area, share residential customers*, *customer density*, and *virtual utility status* capture business context. While *share urban area* is statistically insignificant, it may be collinear with *share residential customers* and *customer density*, which may dominate—hence, the incorrect sign of its coefficient, which is in contrast to the sign for this variable as incorporated into the RHS of the expense model for Wires and Interconnection Services.

[8] This is not an unanticipated result. That is, comp/FTE and regional prices are highly correlated such that the inclusion of both variables will often result in one variable—in the immediate case, regional prices—dominating the other, which is manifest in one variable appearing to be statistically insignificant. While it appears that comp/FTE is not related to the level of expenses for Support Services, it is likely that the underlying relationship is positive but overshadowed by the relationship between the level of expenses and regional prices.

2.2 Simultaneous Equations Model

As first mentioned in Section 3.1 of Part I, an all-in cost model is estimated as a simultaneous equation system with a translog functional form. In addition to determining the variables to cluster the distributors into cohorts, this cost equation system is also used to estimate economies of scale and density, which are reported in Appendix I to this part of the report.

The equation system includes the restricted cost equation covering all variable costs of Ontario's electricity distributors, and three factor demand equations (share equations), for labour, distribution energy losses, and non-labour inputs (other inputs). Only two share equations are independent, since the shares of cost must add up to one, so the estimation process omits the third share equation.

The translog model form can result in fairly large equations because of potentially numerous cross-product terms.[9] In the immediate application, the estimated translog cost equation for Ontario distributors has 66 RHS variables. Accordingly, the full extent of the model results is not reproduced here, but is reported in Appendix II to this part of the report, along with the share equation results.

The variables used in the right-hand side of the cost equation and resource share equations of the simultaneous equation system fall into the three categories including input prices, measures of output, and business context variables. Altogether, 11 variables are utilized. As with the single equation restricted cost models presented above (Equations 2 and 4), the cost equation here also includes (indeed, must include) *capital assets* on the RHS. The input prices include labour price (*comp/FTE*), the unit price of wholesale electricity purchases (*electricity price*). Unlike the single equation models, *regional prices* for quasi-material or "other" inputs is not incorporated into the RHS of the three equation system. For the cost equation of the system, retail sales (*kWh delivered*) is nominally incorporated as the metric for the level of output, along with *annual load factor*. The business context variables

[9] The translog form of the simultaneous cost model is a flexible structural form based upon a Taylor expansion. The coefficients of restricted cost equation and the share equations of the systems are estimated with econometric procedures known as *Seemingly Unrelated Regressions*, with the appropriate restrictions applied to across-equation coefficients

incorporated into the cost equation include *customers/km lines, kWh/customer, northern territory, virtual utility, customers/sq km,* and *share of underground lines*.

Table 5

First-Order Terms of the Cost Equation, Simultaneous Equation Cost Model

Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-value when $H_0 = 0$
Compensation/FTE	0.4050	0.0162	25.01
Electricity price	0.2318	0.0109	21.36
kWh delivered	0.8460	0.1024	8.26
Assets	-0.0396	0.0856	-0.46
Annual Load Factor	-0.0092	0.2766	-0.03
Customers/km line	-0.3674	0.0901	-4.08
kWh/customer	-0.4364	0.1912	-2.28
Northern (0/1 binary variable)	0.0440	0.0341	1.29
Virtual Utility (0/1 binary variable)	-1.1170	0.0996	-11.22
Customers/sq km	0.1004	0.0610	1.65
Share underground line	-0.0137	0.1065	-0.13

Table 6

Summary Statistics, Simultaneous Equation Cost Model

Equation	Observations	Parameters	RMSE	"R-sq"	ChiSq	Prob
All-in Variable Cost	265	65	0.1514	0.9880	30794	0.0000
Labour Share	265	10	0.1065	0.5341	306	0.0000
Electricity Share	265	10	0.0700	0.2379	80	0.0000

The restricted cost equation fits the LDCs data fairly well. All three equations are strongly significant and all of the first-order terms have the hypothesized sign. Because of the large number of “second-order terms,” the “null hypothesis” is not that necessarily that the coefficient assumes a value of zero, and the usual interpretation of the *t*-statistics may not be directly applicable.

Both of the input price variables, *comp/FTE* and *electricity price*, are strongly significant, as is the output variable *kWh sales*. However, the coefficient for *assets* is small, in large part because it is strongly collinear with various combinations of the other variables on the RHS including *kWh, kW, number of customers*, and *km of lines*. The network or business context variables are generally significant, but the full impact of each variable involves interaction with the various cross-product terms. For example, the variable referred to as *share underground*, appears at first to have little impact. However, this variable has significant interaction terms with input variables, capital assets, and with output so that its presence in the model is necessary and significant.

3.0 Comparators and Cohorts

A fair assessment of the costs of the distributors requires that the cohort assignments be based upon the principle of comparability. This means that the costs of individual distributors should be gauged with respect to distributors of similar (comparable) business context. The notion of comparability, in turn, implies that the relevant business context be identified or established through some means.[10]

For the immediate study, the relevant business context factors (cluster variables) to determine the cohorts are drawn exclusively from the estimated econometric models. In addition, the selected variables also satisfy a standard of reasoned intuition. This result follows from the criteria underlying the selection of the cluster variables. First, the selected variables must appear on the RHS of either (or both of) the single equation or simultaneous equation system as a relevant business context factor (cost driver). Second, variables should conform to a standard of plausibility—is it sensible that costs are functionally related to the variable at

[10] Indeed, this is the objective of Step 2 of the C&C methodology, which employs econometric methods to identify the relevant business context descriptors, which are then used to cluster the LDCs into cohort groupings.

issue? In short, if the selected variables explain cost differences among LDCs and appear plausible, a relevant basis of comparability is arguably established.[11]

It is perhaps useful to report on the selected cluster variables with respect to the criteria identified above. Shown by variable type, the number of times that the selected cluster variables appear on the RHS of the cost models is as follows:

> <u>Level of Services Provided (Output)</u>: kwh sales, 2; number of customers, 1;
>
> <u>Inputs and Input Prices</u>: gross assets, 1; compensation/FTE, 2; regional prices, 1;
>
> <u>Network and Business Descriptors</u>: share of underground facilities, 2; virtual utility status, 1;
>
> <u>Market Descriptors</u>: customers/km of lines (density), 3; kWh/customers, 1; share of residential customers, 1; share of territory that is urban, 1.

In summary, *all variables* utilized in the determination of cohorts (clustering) are relevant cost drivers, statistically significant and, most would agree, are intuitively plausible. Output measures such as *kWh sales* are used as a cluster variable in Wires Services, as the unitized costs of the LDCs are a function of the level of output.[12]

The comparators include the diagnostic metrics listed in Section 3.5 of Part I. As discussed above, comparators are reported separately for Wires and Interconnection Services ("Wires") and for Support Services. Distributors are grouped as cohorts in the following tables for each of the two unbundled service categories. In these Comparator and Cohort tables, the distributors are assigned to one of seven cohort groups according to similarity among distributors, for the variables used for clustering. The value for each of the comparator metrics is shown for each distributor.

The comparators are reported as standardized variables, as mentioned. Standardization transforms data, and is particularly useful for comparative purposes because it reveals

---

[11] At a conceptual level, the cluster variables can be defined as weighted RHS variables, where the coefficients (elasticities) of the variables serve as weights. Over the course of the project work, moreover, this approach was employed and compared to the approach incorporated into the current report. While this so-called weighted variables approach is plausible, it does not readily lend itself to the incorporation of intuition, discretion, and variable sets drawn from multiple equations. Nonetheless, at some later point, we anticipate that cost benchmarking of the Ontario distributors can potentially employ a weighted-variables approach.

[12] Please reference Appendix I for a review of scale and density economies.

relative differences in a manner that recognizes the statistical distribution of data.[13] Standardization of a comparator means that the average of the comparator values of all LDCs of a cohort is set equal to zero. In the context of the immediate study, a value of +1.0 for a comparator—which is sometimes referred to as a standardized score—for an individual LDC means that, across all LDCs in the cohort, 16% of the LDCs have higher values; and 32% of the LDCs that are positioned *above the average for the cohort*, have higher values. Similarly, an LDC with a comparator value of +2.0 means that 3% of the LDCs in the cohort are likely to have higher values, while 6% of the LDCs that are above the average for the cohort, have higher values. Where LDCs have comparators that are below the average for its cohort, the standardized comparator values will have negative signs, such as -1.0, -1.3, -2.0, or perhaps of yet larger absolute magnitude.

Comparator and Cohort analysis results are as follows:

SET 1 Cohorts _Wires and Interconnection Services_: The cohort clustering gives rise to three sizable cohorts—cohorts with at least five LDCs—with cohort 3 the largest by far. Six individual LDCs are in small cohorts. These LDCs include Enersource Hydro Mississauga, Hydro Ottawa, and PowerStream grouped into cohort 4; and Northern Ontario Wires, Parry Sound Power, and PUC Distribution assigned to cohort 5. Toronto Hydro and Wasaga Distribution are without peer groups.

SET 2 Cohorts _Support Services_: The cohort grouping results in four sizable cohorts, with one large cohort group (cohort 2) consisting of 40 LDCs. Three LDCs including Hamilton Hydro, Hydro Ottawa, and London Hydro form cohort 5. Scugog Hydro and Toronto Hydro are left without peers.

Most striking is the large size of cohort 3 for Wires and Interconnection Services, which causes the LDCs to be much more concentrated than in Support Services. Cohort membership of course is differentiated between Wires and Support Services, as the cluster variables used to form the cohorts are different for the two service categories, and only a limited degree of consistency in the LDC membership of the cohorts is observed across the

[13] The standardization procedure obtains so-called Z scores, where Z = (Observed Value – Average Value)/Standard Deviation.

Wires and Support Services cohort groupings. Cohort 1 for Wires is very similar to cohort 1 for Support Services. Of the 15 LDCs in cohort 2 for Wires, 8 appear together (in cohort 2) for Support Services. Of the many LDCs in cohort 3 of Wires, many are present in cohorts 2 and 4 of Support Services. Only three LDCs appear to have sufficiently unique business context that they are consistently left without a comparable peer.

Reporting comparators as standardized values provides a means of reporting, for a specific comparator, how much each LDC deviates from the average value for its cohort both in terms of direction—either a positive or negative sign—and magnitude. As mentioned in Section 3.5 of Part I, standardization also preserves confidentiality of the PBR and TB data of the LDCs.

Working through an example may help demonstrate how to utilize the Comparators and Cohorts Phase II study report. As shown in the report for Set 1 Comparators and Cohorts, Wires and Interconnection Services, Page 1, Chapleau PUC is listed as the second member of cohort 2. Several of these comparators are designed to reflect the intensity of capital assets per unit of service level. Notwithstanding the effects on the unit-of-output level of expenses and service quality, a somewhat low level of intensity of capital is desirable, where intensity of capital is captured by several diagnostic comparators including *Assets per customer, Assets per km of lines, Assets per kWh,* , and *Assets per kW*. For these comparators, Chapleau PUC appears to employ modestly low levels of capital—with reported values of -0.46, +0.10, -0.47, and -0.57, respectively. These standardized values should be interpreted to mean that, for Chapleau PUC, capital assets per unit of output resides at a level close to but somewhat below the average level of all LDCs in cohort 2, where Chapleau PUC resides. The view that Chapleau PUC employs a comparatively modest level of capital is supported by an adjacent comparator, *Distribution Transformers per Customers*, where it is shown that its ratio of transformers to customers is also somewhat below the average of the LDCs in cohort 2. These diagnostic comparators suggest that, absent other information, Board staff may not have apparent cause for further exploration of the level of capital assets for wires services employed by Chapleau PUC, as far as the inclusion of assets are incorporated with the rate application of Chapleau PUC in the 2006 EDR.

In contrast, Great Lakes Power, which is also grouped into cohort 2 because its business context is similar to that of Chapleau PUC, appears to have an unusually high level of capital, as employed in Wires Services; the respective comparator values are +3.29, -0.74, +3.38, and +3.34. This high concentration of capital is also suggested by the value for the comparator, *Distribution Transformers per customer*, where Great Lakes Power is +2.86 standard deviations above the average value for the LDCs of comparable business context. Based upon the comparators and cohorts analysis contained herein, Board staff would be advised to examine more closely the rate base assets of Wires for Great Lakes Power, and that less attention should be given to the Wires assets of Chapleau PUC.

As a general rule, Board staff should look for unusual values, which can be quickly gleaned from the tables. For the consideration of Board staff, a few obvious concerns about LDC cost experience can be cited. Namely, it appears that Niagara-on-the-Lake, Great Lakes Power, and Festival Hydro utilize capital with comparative high intensity in Wires and Interconnection Services, though Festival Hydro reveals lower costs elsewhere.
For the level of operating expenses for Wires, Asphodel-Norwood Distribution, and Great Lakes Hydro appear to have fairly high values, as does Dutton Hydro, notwithstanding Dutton Hydro's comparatively low values for labour compensation. Eastern Ontario Power appears to also have an overall high level of expenses per unit of output for its business context group (cohort) although its use of direct labour resources (FTEs) is of a normal level (< +1.0). For resource and cost experience for Support Services, Atikokan Hydro appears to have somewhat high levels of operating expenses, stated on a per unit of output basis; Atikokan Hydro's utilization of capital, however, appears to be comparatively low.[14]

In summary, the interpretation and use of the comparators is straightforward, and Board and Board staff are encouraged to use the Phase II Comparators and Cohorts report to help screen the rate applications of the LDCs. Board staff should examine the comparator and cohort tables for anomalous values for the various comparators, as reported, with particular emphasis given to consistently high or low values, where all comparators are reported as

[14] Comparators involving assets implicitly face measurement issues related to the valuation of capital. A real capital stock is the better metric for capital, and comparators based upon the real capital stock can be readily developed for application in a potential follow up C&C study.

standardized values. As mentioned above, the average comparator value of a cohort is set equal to zero. For screening the rate applications, a threshold value of +1.2 to +1.5 appears plausible.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Assets per Customer	Asset per km Line	Assets per kWh	Assets per kW	Distribution Transformers per Customer	Distribution losses per km Line	Expenses per Customer	Expenses per kWh
Asphodel-Norwood Distribution	1	-1.09	-1.05	-.96	-1.07	1.87	-.05	1.15	1.69
Essex Powerlines	1	-.52	-.35	-.43	-.60	-.89	-.07	.61	.89
Lakefield Distribution	1	-.22	-.39	-.46	-.38	.34	-.70	.93	.66
Peterborough Distribution	1	.55	1.22	.18	.26	-1.26	-.12	-.54	-.65
Scugog Hydro	1	.38	1.44	.31	.42	-.72	1.87	-.37	-.29
Tillsonburg Hydro	1	-.44	-.72	-1.32	-1.05	-.03	1.03	.28	-.82
Wellington Electric Distribut	1	-.74	-.95	.97	.46	.69	-.90	-1.98	-1.31
Whitby Hydro	1	2.08	.79	1.70	1.95	.00	-1.06	-.08	-.17
Atikokan Hydro	2	-.71	-1.16	-.55	-.56	-.21	-.32	1.17	.99
Chapleau PUC	2	-.46	.10	-.47	-.57	-.54	.49	.59	.29
Espanola Regional Hydro	2	-.59	-.88	-.39	-.33	-.24	-1.12	-.07	.11
Fort Frances Power	2	-.10	.61	-.07	-.11	-.13	.09	-.79	-.59
Gravenhurst Hydro	2	-.41	-.78	-.02	-.13	.87	.11	-.70	-.21
Great Lakes Power	2	3.29	-.74	3.38	3.34	2.86	-1.25	2.78	3.20
Greater Sudbury Hydro	2	.59	1.88	.45	.63	-.89	1.00	-.27	-.17
Hearst Power	2	-.89	-.74	-.97	-.97	.05	.34	-.45	-.91
Kenora Hydro	2	-.46	.49	-.25	-.22	-.90	.63	-.70	-.40
Lakeland Power	2	-.34	-1.15	-.43	-.40	-.13	-1.17	-.45	-.52
North Bay Hydro	2	.27	.80	-.06	.03	-.42	-.98	-.18	-.35
Sioux Lookout Hydro	2	-.08	-1.07	-.52	-.58	1.33	-.07	.93	-.07
Terrace Bay Superior Wires	2	.31	1.14	.24	-.02	-.27	-.14	-.81	-.61
Thunder Bay Hydro	2	.08	.28	.02	.24	-.70	-.25	-.07	-.05
West Nipissing Energy	2	-.50	1.22	-.36	-.36	-.70	2.63	-.97	-.71
Aurora Hydro	3	.88	.56	.65	1.07	-.10	1.39	-.92	-.87
Barrie Hydro	3	.79	.46	1.03	1.23	-.15	-.37	-.33	-.11
Bluewater Power	3	-.18	-.25	-.68	-.49	-.20	-.37	.45	-.28
Brant County Power	3	-.69	-1.47	-.67	-.74	2.90	-.93	2.34	1.90
Brantford Power	3	-.76	.32	-.84	-.72	-1.16	.63	.52	.19

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Assets per Customer	Asset per km Line	Assets per kWh	Assets per kW	Distribution Transformers per Customer	Distribution losses per km Line	Expenses per Customer	Expenses per kWh
Burlington Hydro	3	.73	.41	.31	.27	-.05	-.13	.34	-.04
Cambridge and North Dumfries	3	.99	.68	.08	.41	-.11	-.04	.06	-.57
Centre Wellington Hydro	3	-.08	-.23	-.11	.09	-.29	-.22	.04	-.02
Chatham-Kent Hydro	3	-.57	-.66	-.70	-.66	-.80	-.18	.16	-.12
Clinton Power	3	-1.48	-.88	-1.06	-1.16	.00	.65	-.30	.53
Collus Power	3	-.77	-.84	-.87	-.84	-.03	-.29	.48	.12
Dutton Hydro	3	-1.08	-.29	-.23	-.17	-.69	-.26	.91	2.71
Eastern Ontario Power	3	-2.31	-2.12	-2.16	-2.26	.22	-.67	2.95	2.78
ELK Energy	3	-.53	.59	-.02	-.20	-.15	1.29	-1.09	-.58
Embrun Hydro	3	-.52	.02	.33	-.22	.22	-.01	-2.05	-1.54
EnWin Powerlines	3	.41	1.66	-.20	-.44	-1.07	.58	-1.08	-1.21
Erie Thames Powerlines	3	-.85	-.60	-1.04	-1.08	-.70	-.60	2.15	1.10
Festival Hydro	3	1.22	2.62	.22	.84	-.41	.20	-.38	-.84
Grand Valley Energy	3	-.55	.79	.80	.74	.32	.26	-1.68	-.86
Grimsby Power	3	-.13	-.40	.78	.24	.03	-.93	-.99	-.27
Guelph Hydro	3	.20	.20	-.55	-.22	-.70	-.38	-.52	-.99
Haldimand County Hydro	3	-.27	.21	.45	.46	2.68	.07	1.94	3.01
Halton Hills Hydro	3	-.42	-1.59	-.38	-.53	.80	-1.21	.12	.10
Hamilton Hydro	3	.08	1.25	.16	.02	-1.03	.20	-.13	-.04
Hydro 2000	3	-1.82	-1.64	-1.70	-1.91	.07	-1.17	-1.87	-1.59
Hydro Hawkesbury	3	-1.96	-1.57	-1.95	-2.04	-.19	2.33	-1.21	-1.45
Hydro One Brampton Networks	3	1.62	1.47	.68	.99	-.54	-.17	-.88	-1.07
Hydro Vaughan	3	1.99	.59	.40	.19	.35	-.46	-.50	-1.06
Innisfil Hydro	3	.70	-.76	2.15	1.43	1.57	-1.17	-.16	.92
Kingston Electricity	3	-1.18	-.42	-1.20	-1.28	-1.33	.92	.51	.16
Kitchener-Wilmot Hydro	3	1.00	.75	.83	1.33	-.57	-.56	-.31	-.33
Lakefront Utilities	3	.11	2.01	-.43	-.25	-1.62	3.98	-.39	-.77
London Hydro	3	.09	.47	.09	.27	-.88	-.91	.42	.35
Markham Hydro	3	1.23	.36	.68	.35	.20	-.64	-.14	-.41
Middlesex Power	3	-.14	.56	-.06	-.38	.25	1.21	-1.02	-.83

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Assets per Customer	Asset per km Line	Assets per kWh	Assets per kW	Distribution Transformers per Customer	Distribution losses per km Line	Expenses per Customer	Expenses per kWh
Midland Power	3	-.18	.29	-.78	-.64	.44	.08	.76	-.24
Milton Hydro	3	.10	-1.00	-.55	-.33	1.64	-.80	-.22	-.77
Newmarket Hydro	3	.80	.39	.59	.64	-.58	-.48	.07	-.07
Niagara Falls Hydro	3	.77	.60	.88	.97	-.70	-.12	.87	.88
Niagara-on-the-Lake Hydro	3	2.24	-.13	2.32	2.16	1.50	-.70	.34	.40
Norfolk Power	3	1.41	-.41	2.19	2.74	2.43	-.80	.32	.86
Oakville Hydro	3	.73	.30	.06	.10	-.13	-.34	.22	-.34
Orangeville Hydro	3	.15	1.08	.21	.49	-.50	-.34	-.60	-.47
Orillia Power	3	.57	.21	.38	.01	-.24	-.37	1.64	1.17
Oshawa PUC Networks	3	-.08	-.77	.04	.00	-.66	-.69	-1.12	-.89
Ottawa River Power	3	-.04	.95	.40	.32	.15	-.63	.10	.53
PenWest Utilities	3	.73	-1.46	.78	.80	2.65	-1.29	2.09	1.88
Port Colborne Hydro	3	-2.31	-2.12	-2.16	-2.26	1.36	-.57	-.03	.51
Renfrew Hydro	3	.46	1.04	.59	.45	-.89	.74	-.36	-.20
Richmond Hill Hydro	3	1.85	-.05	2.10	1.32	-.51	-.97	-.19	.02
Rideau St. Lawrence	3	-1.52	-1.08	-1.33	-1.54	.35	1.88	-.54	-.27
St. Catharines Hydro	3	-.17	.91	-.25	-.23	-.71	.00	.15	.01
St. Thomas Energy	3	-.09	.69	-.03	.19	-1.25	.25	-.42	-.32
Tay Hydro	3	-.45	-1.72	1.84	1.19	.30	-1.22	-.84	1.15
Veridian Connections	3	.28	1.05	.27	.49	-.29	.58	-.94	-.80
Waterloo North Hydro	3	1.32	.41	.96	1.32	.75	-.29	1.13	.69
Welland Hydro	3	-.44	-.25	-.28	-.06	-1.08	-.30	.24	.36
Wellington North Power	3	-.27	-1.02	-.35	-.23	1.05	-.26	-1.28	-1.15
West Coast Huron	3	-.97	-.60	-1.37	-1.29	-.78	2.14	.70	-.43
West Perth Power	3	.06	.68	-.45	-.24	-.51	2.30	.31	-.31
Woodstock Hydro	3	-.66	-.28	-.83	-.68	-.65	.19	.16	-.19
Enersource Hydro Mississauga	4	.88	-1.13	-.88	-1.03	-.69	-1.13	.84	-.98
Hydro Ottawa	4	-1.09	.77	-.21	.06	-.45	.76	.27	1.02
PowerStream	4	.20	.36	1.09	.97	1.15	.37	-1.11	-.04

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Assets per Customer	Asset per km Line	Assets per kWh	Assets per kW	Distribution Transformers per Customer	Distribution losses per km Line	Expenses per Customer	Expenses per kWh
Northern Ontario Wires	5	-1.03	-1.14	-1.08	-1.13	-1.10	-1.14	-.91	-.68
Parry Sound Power	5	.97	.40	.90	.77	.86	.40	-.16	-.47
PUC Distribution	5	.05	.74	.18	.36	.24	.74	1.07	1.15
Toronto Hydro	6	NA	NA	NA	NA	NA	NA	NA	NA
Wasaga Distribution	7	NA	NA	NA	NA	NA	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Expenses per km Line	Expense per Assets	FTE per Customer	FTE per kWh	Labour Compensation per Customer	Labour Compensation per kWh	Labour Compensation per kW
Asphodel-Norwood Distribution	1	1.30	1.96	-.35	-.35	.00	.00	.00
Essex Powerlines	1	.80	.53	-.35	-.35	.00	.00	.00
Lakefield Distribution	1	.58	.42	-.35	-.35	.00	.00	.00
Peterborough Distribution	1	-.19	-.67	-.35	-.35	.00	.00	.00
Scugog Hydro	1	.28	-.55	-.35	-.35	.00	.00	.00
Tillsonburg Hydro	1	-.10	.25	-.35	-.35	.00	.00	.00
Wellington Electric Distribut	1	-1.89	-1.10	2.47	2.47	.00	.00	.00
Whitby Hydro	1	-.79	-.83	-.35	-.35	.00	.00	.00
Atikokan Hydro	2	-.02	2.71	1.28	.97	.62	.50	-.45
Chapleau PUC	2	2.46	1.09	.79	.35	.38	.12	1.82
Espanola Regional Hydro	2	-.49	.58	-.65	-.38	.55	.62	.03
Fort Frances Power	2	-.20	-.82	-.64	-.44	-.65	-.47	.03
Gravenhurst Hydro	2	-1.14	-.47	-.38	.20	-.76	-.26	-1.13
Great Lakes Power	2	-1.12	-.50	2.92	3.13	2.94	3.23	-1.07
Greater Sudbury Hydro	2	.97	-.80	-.43	-.30	-.34	-.23	.74
Hearst Power	2	.04	.84	-.79	-1.13	-.66	-.99	-.29
Kenora Hydro	2	.52	-.40	-.71	-.38	-.62	-.33	.61
Lakeland Power	2	-1.49	-.28	-.24	-.41	-.50	-.55	-1.44
North Bay Hydro	2	.53	-.57	-.86	-.82	.47	.06	1.38
Sioux Lookout Hydro	2	-.83	.68	.13	-.56	.40	-.35	-1.06
Terrace Bay Superior Wires	2	-.28	-1.03	-.31	-.21	-1.11	-.84	-.75
Thunder Bay Hydro	2	.35	-.35	-.14	-.12	.12	.09	.52
West Nipissing Energy	2	.71	-.68	.04	.12	-.83	-.59	1.06
Aurora Hydro	3	-.86	-.94	-.54	-.49	-.72	-.79	-.71
Barrie Hydro	3	-.45	-.68	-.39	-.14	.83	1.22	.45
Bluewater Power	3	.23	.20	.48	-.34	1.50	.69	1.10
Brant County Power	3	-.33	2.25	1.30	.69	.24	.26	-.86
Brantford Power	3	2.08	.92	-.44	-.49	-.98	-1.08	-.25

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Expenses per km Line	Expense per Assets	FTE per Customer	FTE per kWh	Labour Compensation per Customer	Labour Compensation per kWh	Labour Compensation per kW
Burlington Hydro	3	.02	-.38	-.81	-.75	-.16	-.37	-.30
Cambridge and North Dumfries	3	-.14	-.59	-.50	-.82	.08	-.47	-.09
Centre Wellington Hydro	3	-.16	-.12	1.03	.51	-.27	-.27	-.36
Chatham-Kent Hydro	3	-.08	.39	-1.36	-1.01	-.34	-.49	-.42
Clinton Power	3	.87	1.87	2.05	2.52	-.50	.18	.35
Collus Power	3	.11	.91	-1.99	-1.36	-.66	-.79	-.68
Dutton Hydro	3	2.35	1.98	3.46	4.80	-.88	-.10	-.19
Eastern Ontario Power	3	.40		.33	.27	-.65	-.55	-1.05
ELK Energy	3	-.13	-.55	-.25	.28	-.71	-.32	.08
Embrun Hydro	3	-1.52	-1.24	-.90	.04	-1.70	-1.60	-1.37
EnWin Powerlines	3	-.29	-.90	-1.18	-1.06	-1.02	-1.26	-.47
Erie Thames Powerlines	3	2.16	2.50	.42	-.19	1.68	1.14	1.79
Festival Hydro	3	.45	-.81	.60	-.33	1.31	.46	2.32
Grand Valley Energy	3	-.81	-.97	.21	1.71	-1.63	-1.37	-1.15
Grimsby Power	3	-.97	-.68	-.77	.09	-.92	-.43	-.91
Guelph Hydro	3	-.43	-.56	.18	-.59	-.92	-1.27	-.78
Haldimand County Hydro	3	2.35	1.21	.00	.64	-.10	.66	.27
Halton Hills Hydro	3	-1.38	.20	.23	.09	1.18	1.31	-.86
Hamilton Hydro	3	.88	-.30	-1.02	-.65	-.09	.03	.74
Hydro 2000	3	-1.46	.15	-.45	-.34	-1.62	-1.66	-1.35
Hydro Hawkesbury	3	-.24	3.23	-1.09	-1.20	-.75	-1.22	.07
Hydro One Brampton Networks	3	-.73	-1.05	-.67	-.82	.08	-.36	.03
Hydro Vaughan	3	-.93	-.98	-.19	-.83	.61	-.30	-.20
Innisfil Hydro	3	-1.11	-.58	-.90	.11	-.91	-.31	-1.23
Kingston Electricity	3	1.90	1.84	-.49	-.53	1.63	1.38	3.23
Kitchener-Wilmot Hydro	3	-.37	-.73	.14	-.04	2.04	2.07	1.48
Lakefront Utilities	3	1.10	-.46	-.75	-.87	-.23	-.63	1.02
London Hydro	3	.70	-.02	-.30	-.24	1.10	1.21	1.33
Markham Hydro	3	-.59	-.72	-.45	-.57	.42	.13	-.15
Middlesex Power	3	-.42	-.70	1.34	.85	-.80	-.75	-.35

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Expenses per km Line	Expense per Assets	FTE per Customer	FTE per kWh	Labour Compensation per Customer	Labour Compensation per kWh	Labour Compensation per kW
Midland Power	3	1.16	.38	1.46	-.04	.81	.00	1.18
Milton Hydro	3	-1.10	-.37	-.13	-.68	.00	-.55	-.84
Newmarket Hydro	3	-.22	-.52	-.53	-.47	.46	.40	.11
Niagara Falls Hydro	3	.55	-.18	.53	.37	1.47	1.79	1.08
Niagara-on-the-Lake Hydro	3	-.95	-.78	.93	.64	1.27	1.57	-.38
Norfolk Power	3	-.90	-.61	.74	.98	1.35	2.35	-.28
Oakville Hydro	3	-.15	-.43	-.53	-.74	-.41	-.74	-.54
Orangeville Hydro	3	.14	-.58	-.66	-.43	-.53	-.46	.04
Orillia Power	3	.87	.26	.21	-.05	.74	.66	.32
Oshawa PUC Networks	3	-1.29	-.78	-.45	-.26	-.59	-.50	-.91
Ottawa River Power	3	1.03	-.11	.69	.85	.13	.64	.91
PenWest Utilities	3	-1.16	.35	.25	.16	.17	.30	-1.24
Port Colborne Hydro	3	-.57		-2.06	-1.17	-1.37	-1.23	-1.29
Renfrew Hydro	3	.10	-.59	.24	.21	-.10	.07	.27
Richmond Hill Hydro	3	-1.02	-.87	-.28	-.07	.11	.38	-.73
Rideau St. Lawrence	3	.23	1.62	.82	.71	-.15	.11	.51
St. Catharines Hydro	3	1.24	.02	-.27	-.31	.41	.37	1.40
St. Thomas Energy	3	.26	-.38	-.18	-.13	-.60	-.55	-.10
Tay Hydro	3	-1.71	-.43	.14	2.63	-.98	.39	-1.47
Veridian Connections	3	-.35	-.81	-1.95	-1.26	.13	.20	.66
Waterloo North Hydro	3	.17	-.30	.36	-.01	3.08	2.87	1.52
Welland Hydro	3	.36	.31	-.59	-.32	.48	.75	.56
Wellington North Power	3	-1.44	-.80	.71	.24	-.84	-.90	-1.11
West Coast Huron	3	1.13	1.50	2.28	.11	.04	-.70	.40
West Perth Power	3	.85	-.06	1.51	.21	-1.84	-1.92	-1.52
Woodstock Hydro	3	.55	.50	.44	-.10	.62	.33	.95
Enersource Hydro Mississauga	4	-.97	-.54	-1.15	-1.15	-1.08	-1.08	-1.00
Hydro Ottawa	4	1.03	1.15	.48	.66	.90	.90	1.00
PowerStream	4	-.07	-.61	.67	.49	.18	.18	-.01

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Expenses per km Line	Expense per Assets	FTE per Customer	FTE per kWh	Labour Compensation per Customer	Labour Compensation per kWh	Labour Compensation per kW
Northern Ontario Wires	5	-.80	1.02	1.15	1.15	1.15	1.15	1.15
Parry Sound Power	5	-.32	-.98	-.58	-.58	-.58	-.58	-.58
PUC Distribution	5	1.12	-.04	-.58	-.58	-.58	-.58	-.58
Toronto Hydro	6	NA	NA	NA	NA	NA	NA	NA
Wasaga Distribution	7	NA	NA	NA	NA	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Non-labour Expense per Customer	Non-labour Expense per kWh	Non-labour Expense per kW	Labour Compensation /Total Expense	Non-labour Expense /Total Expense
Asphodel-Norwood Distribution	1	1.14	1.67	1.29	.00	.35
Essex Powerlines	1	.61	.88	.80	.00	.35
Lakefield Distribution	1	.92	.66	.58	.00	.35
Peterborough Distribution	1	-.52	-.62	-.18	.00	.35
Scugog Hydro	1	-.35	-.27	.29	.00	.35
Tillsonburg Hydro	1	.29	-.79	-.09	.00	.35
Wellington Electric Distribut	1	-2.00	-1.38	-1.91	.00	-2.47
Whitby Hydro	1	-.08	-.16	-.78	.00	.35
Atikokan Hydro	2	1.38	1.32	.27	-1.12	.49
Chapleau PUC	2	1.03	.74	2.72	-.59	.80
Espanola Regional Hydro	2	-.41	-.23	-.62	1.71	-.65
Fort Frances Power	2	-1.00	-.84	-.64	.68	-1.02
Gravenhurst Hydro	2	-.44	.01	-.69	-.27	.49
Great Lakes Power	2	2.11	2.80	-.84	-.01	-.15
Greater Sudbury Hydro	2	-.16	-.07	.87	-.29	.19
Hearst Power	2	.00	-.67	.59	-.81	.98
Kenora Hydro	2	-.39	-.16	.81	.31	.62
Lakeland Power	2	-.35	-.44	-1.05	-.23	.12
North Bay Hydro	2	-.81	-.81	-.50	1.93	-1.32
Sioux Lookout Hydro	2	1.38	.30	-.32	-1.15	.78
Terrace Bay Superior Wires	2	-.18	-.09	.62	-1.45	1.68
Thunder Bay Hydro	2	-1.04	-.90	-.92	.47	-1.88
West Nipissing Energy	2	-1.13	-.95	-.30	.82	-1.15
Aurora Hydro	3	-.48	-.49	-.52	-.08	-.14
Barrie Hydro	3	-1.02	-.92	-1.00	1.41	-1.54
Bluewater Power	3	-.46	-.57	-.47	1.08	-.79
Brant County Power	3	2.57	2.11	.51	-1.05	1.43
Brantford Power	3	1.31	.89	2.86	-1.43	1.55

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Non-labour Expense per Customer	Non-labour Expense per kWh	Non-labour Expense per kW	Labour Compensation /Total Expense	Non-labour Expense /Total Expense
Burlington Hydro	3	.09	-.10	-.03	-.52	.02
Cambridge and North Dumfries	3	-.14	-.39	-.22	-.04	-.17
Centre Wellington Hydro	3	-.10	-.15	-.18	-.42	-.09
Chatham-Kent Hydro	3	.42	.18	.27	-.59	.63
Clinton Power	3	.05	.39	.72	-.43	.40
Collus Power	3	1.13	.72	.87	-1.09	1.35
Dutton Hydro	3	1.88	3.26	3.54	-1.45	1.87
Eastern Ontario Power	3	4.07	3.73	1.75	-1.68	2.21
ELK Energy	3	-.67	-.53	-.41	.21	-.51
Embrun Hydro	3	-.78	-.60	-.68	-.73	.72
EnWin Powerlines	3	-.34	-.48	.03	-.45	.42
Erie Thames Powerlines	3	.79	.35	.99	-.07	.00
Festival Hydro	3	-.86	-.83	-.74	2.16	-1.23
Grand Valley Energy	3	-.41	.04	.09	-1.19	1.49
Grimsby Power	3	-.52	-.29	-.58	-.37	-.20
Guelph Hydro	3	-.72	-.76	-.70	-.84	-.92
Haldimand County Hydro	3	2.20	2.87	2.87	-1.15	1.36
Halton Hills Hydro	3	-.66	-.61	-.91	1.15	-.99
Hamilton Hydro	3	-.19	-.18	.25	-.06	-.14
Hydro 2000	3	-.64	-.59	-.60	-.83	.96
Hydro Hawkesbury	3	-.66	-.74	-.37	.36	-.38
Hydro One Brampton Networks	3	-.86	-.83	-.84	1.30	-1.13
Hydro Vaughan	3	-.93	-.89	-.94	1.39	-1.35
Innisfil Hydro	3	.63	1.26	-.23	-1.06	1.29
Kingston Electricity	3	-.47	-.50	-.10	1.13	-.83
Kitchener-Wilmot Hydro	3	-.74	-.69	-.73	3.00	-1.02
Lakefront Utilities	3	-.32	-.47	.30	.03	-.20
London Hydro	3	-.65	-.60	-.56	.70	-1.04
Markham Hydro	3	-.68	-.68	-.75	.58	-.96
Middlesex Power	3	-.50	-.46	-.31	-.08	-.11

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Non-labour Expense per Customer	Non-labour Expense per kWh	Non-labour Expense per kW	Labour Compensation /Total Expense	Non-labour Expense /Total Expense
Midland Power	3	.17	-.23	.43	.13	-.08
Milton Hydro	3	-.40	-.56	-.71	.15	-.45
Newmarket Hydro	3	-.07	-.15	-.19	.39	-.06
Niagara Falls Hydro	3	-.33	-.30	-.36	.62	-.74
Niagara-on-the-Lake Hydro	3	-.61	-.55	-.82	.97	-.98
Norfolk Power	3	-.73	-.60	-.87	1.08	-1.13
Oakville Hydro	3	.12	-.17	-.05	-.70	.14
Orangeville Hydro	3	-.45	-.42	-.19	-.18	-.33
Orillia Power	3	1.08	.78	.79	-.46	.48
Oshawa PUC Networks	3	-.84	-.76	-.89	.51	-.97
Ottawa River Power	3	-.25	-.12	.12	-.02	-.35
PenWest Utilities	3	1.54	1.35	-.44	-1.02	.68
Port Colborne Hydro	3	1.28	1.58	.64	-1.68	2.21
Renfrew Hydro	3	-.46	-.41	-.31	.18	-.49
Richmond Hill Hydro	3	-.38	-.31	-.67	.26	-.42
Rideau St. Lawrence	3	-.68	-.59	-.50	.33	-.83
St. Catharines Hydro	3	-.67	-.64	-.45	.25	-1.02
St. Thomas Energy	3	-.05	-.06	.31	-.47	.35
Tay Hydro	3	-.17	.80	-.83	-.65	.53
Veridian Connections	3	-.42	-.41	-.21	1.55	.02
Waterloo North Hydro	3	-.59	-.59	-.69	1.72	-1.09
Welland Hydro	3	-.23	-.19	-.16	.24	-.39
Wellington North Power	3	-.52	-.52	-.72	.30	.16
West Coast Huron	3	.67	-.03	1.03	-.55	.56
West Perth Power	3	2.17	1.17	2.97	-2.26	3.03
Woodstock Hydro	3	-.52	-.56	-.39	.48	-.79
Enersource Hydro Mississauga	4	1.14	1.07	-.06	-1.15	1.15
Hydro Ottawa	4	-.43	-.16	1.03	.68	-.46
PowerStream	4	-.72	-.91	-.97	.47	-.69

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
WIRES AND INTERCONNECTIONS SERVICES

LDC Name	Cohort	Non-labour Expense per Customer	Non-labour Expense per kWh	Non-labour Expense per kW	Labour Compensation /Total Expense	Non-labour Expense /Total Expense
Northern Ontario Wires	5	-1.07	-.98	-.87	1.15	-1.15
Parry Sound Power	5	.15	-.05	-.22	-.58	.58
PUC Distribution	5	.92	1.02	1.09	-.58	.58
Toronto Hydro	6	NA	NA	NA	NA	NA
Wasaga Distribution	7	NA	NA	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Assets per Customer	Expenses per Customer	Expenses per Assets	Labour Expense per Customer	Non-labour Expenses per Customer
Asphodel-Norwood Distribution	1	-0.80	-0.46	-0.95	-0.41	-0.18
Essex Powerlines	1	-0.51	-0.32	1.81	-0.41	-0.01
Lakefield Distribution	1	-0.03	-0.57	-0.96	-0.41	-0.32
Northern Ontario Wires	1	0.08	2.00	-0.25	2.71	-0.06
Parry Sound Power	1	0.27	1.51	-0.72	-0.41	2.15
Peterborough Distribution	1	-0.24	-0.65	1.09	-0.41	-0.41
PUC Distribution	1	0.15	-0.05	1.13	-0.41	0.30
Tillsonburg Hydro	1	-0.73	0.04	-0.02	-0.41	0.40
Wellington Electric Distribut	1	-0.80	-1.27	-0.91	0.57	-1.96
Whitby Hydro	1	2.60	-0.23	-0.21	-0.41	0.08
Atikokan Hydro	2	2.90	1.15	-0.65	2.70	-0.10
Barrie Hydro	2	-0.21	-1.35	0.97	-0.95	-1.09
Brantford Power	2	-0.36	-0.38	0.96	-0.39	-0.08
Centre Wellington Hydro	2	1.36	0.33	-0.53	1.56	-0.47
Chapleau PUC	2	-1.06	0.85	-0.50	0.09	0.84
Chatham-Kent Hydro	2	-0.17	-1.10	0.24	-1.36	-0.43
Clinton Power	2	-1.29	0.16	-0.41	0.02	0.15
Collus Power	2	-0.78	-0.87	0.04	-2.10	0.33
Dutton Hydro	2	-0.96	0.83	-0.61	0.01	0.95
ELK Energy	2	0.47	-0.51	-0.40	0.23	-0.78
Embrun Hydro	2	-1.40	-0.08	-0.33	-0.71	0.36
EnWin Powerlines	2	-1.24	-1.51	5.15	-1.25	-1.00
Erie Thames Powerlines	2	-0.89	0.47	0.67	-0.55	0.80
Festival Hydro	2	0.60	-0.73	-0.24	0.18	-1.08
Fort Frances Power	2	0.31	1.22	-0.48	0.03	1.40
Grand Valley Energy	2	-0.81	1.78	-0.60	-0.05	2.12
Greater Sudbury Hydro	2	0.07	-0.74	0.61	-0.47	-0.59
Guelph Hydro	2	-0.43	-0.76	1.09	2.20	-1.17
Hearst Power	2	0.86	-0.77	-0.63	-0.96	-0.34
Hydro 2000	2	-1.38	0.09	-0.45	-0.58	0.46
Hydro Hawkesbury	2	-0.11	-0.36	-0.48	-1.82	0.67

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Assets per Customer	Expenses per Customer	Expenses per Assets	Labour Expense per Customer	Non-labour Expenses per Customer
Kenora Hydro	2	0.39	0.22	-0.47	-0.39	0.30
Kingston Electricity	2	-0.94	-0.51	1.32	-0.66	-0.67
Lakefront Utilities	2	-0.49	-0.90	-0.33	-0.68	-0.67
Middlesex Power	2	1.83	-0.24	-0.56	0.21	-0.45
Niagara Falls Hydro	2	0.95	0.76	0.54	0.52	0.35
Orangeville Hydro	2	1.85	-0.65	-0.53	0.14	-0.79
Orillia Power	2	1.43	0.09	-0.39	-0.34	0.28
Ottawa River Power	2	-0.03	-0.35	-0.30	-0.32	-0.17
Renfrew Hydro	2	0.29	-0.31	-0.55	0.49	-0.72
Rideau St. Lawrence	2	-1.27	0.29	0.30	1.85	-0.84
St. Catharines Hydro	2	0.00	-1.29	0.54	0.03	-1.27
St. Thomas Energy	2	0.32	-0.54	-0.25	-0.48	-0.32
Terrace Bay Superior Wires	2	-0.88	1.61	-0.56	1.31	1.03
Welland Hydro	2	0.00	-0.42	0.08	-0.45	-0.30
Wellington North Power	2	0.63	2.51	-0.49	0.95	2.18
West Coast Huron	2	-0.61	1.11	-0.35	0.90	0.71
West Nipissing Energy	2	0.52	-1.37	-0.63	0.28	-1.69
West Perth Power	2	-0.45	2.40	-0.48	-0.07	2.88
Woodstock Hydro	2	0.95	-0.15	-0.32	0.85	-0.81
Aurora Hydro	3	0.41	0.16	-0.83	0.54	-0.17
Enersource Hydro Mississauga	3	0.79	-0.41	0.48	-0.91	0.56
Hydro One Brampton Networks	3	-0.10	-1.65	-0.24	-0.28	-1.01
Hydro Vaughan	3	1.23	-0.36	-0.44	-0.24	-0.35
Markham Hydro	3	-0.44	-0.74	-0.23	0.32	-0.86
Newmarket Hydro	3	1.39	2.36	-0.66	0.65	1.36
Oakville Hydro	3	-0.19	0.06	-0.35	1.01	-0.34
PowerStream	3	0.18	-0.17	1.05	0.70	-0.85
Richmond Hill Hydro	3	-0.44	-0.10	-0.41	-0.13	0.04
Veridian Connections	3	-2.22	0.88	2.49	-2.46	2.18
Wasaga Distribution	3	-0.62	-0.04	-0.86	0.79	-0.57

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Assets per Customer	Expenses per Customer	Expenses per Assets	Labour Expense per Customer	Non-labour Expenses per Customer
Bluewater Power	4	0.73	0.59	0.96	0.74	-0.12
Brant County Power	4	-0.16	0.81	-0.40	0.34	0.63
Burlington Hydro	4	0.66	-0.88	0.59	-0.27	-0.68
Cambridge and North Dumfries	4	-0.41	-0.88	1.30	-0.62	-0.60
Eastern Ontario Power	4	-1.92	2.82		-0.44	3.51
Espanola Regional Hydro	4	-0.17	-0.21	-1.12	-0.42	-0.26
Gravenhurst Hydro	4	0.83	0.38	-1.01	0.30	0.20
Great Lakes Power	4	3.46	2.74	-0.70	3.92	0.59
Grimsby Power	4	0.01	-0.76	-0.90	-0.20	-0.66
Haldimand County Hydro	4	-0.18	-0.34	0.04	-0.54	0.01
Halton Hills Hydro	4	-0.84	0.03	1.10	0.08	-0.27
Innisfil Hydro	4	-0.39	-0.30	-0.28	-0.53	0.01
Kitchener-Wilmot Hydro	4	0.35	-1.35	0.58	-0.57	-0.89
Lakeland Power	4	-0.45	-0.26	-0.60	0.07	-0.35
Midland Power	4	0.11	0.34	-0.85	-0.04	0.30
Milton Hydro	4	0.41	-0.31	-0.47	0.27	-0.54
Niagara-on-the-Lake Hydro	4	0.96	-0.61	-1.10	-0.20	-0.77
Norfolk Power	4	0.82	-0.27	-0.55	0.95	-0.82
North Bay Hydro	4	-0.03	-0.48	0.02	-0.86	-0.20
Oshawa PUC Networks	4	-0.31	-0.28	2.35	0.69	-0.77
PenWest Utilities	4	-0.52	1.04	0.73	-0.90	2.05
Port Colborne Hydro	4	-1.92	-0.68		-1.76	0.36
Sioux Lookout Hydro	4	-0.50	0.54	-1.02	-0.62	1.16
Tay Hydro	4	-0.23	-0.09	-1.04	0.08	-0.12
Thunder Bay Hydro	4	-0.31	-0.58	1.84	0.73	-0.90
Waterloo North Hydro	4	0.03	-1.00	0.53	-0.20	-0.87
Hamilton Hydro	5	-0.36	0.28	0.95	-0.45	1.13
Hydro Ottawa	5	1.13	-1.11	-1.05	-0.69	-0.78
London Hydro	5	-0.77	0.83	0.10	1.15	-0.35
Scugog Hydro	6	NA	NA	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Assets per Customer	Expenses per Customer	Expenses per Assets	Labour Expense per Customer	Non-labour Expenses per Customer
Toronto Hydro	7	NA	NA	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Labour Expense Over Expense	Non-labour Expense Over Expenses	FTE per Customer
Asphodel-Norwood Distribution	1	-0.47	0.48	-0.41
Essex Powerlines	1	-0.47	0.47	-0.41
Lakefield Distribution	1	-0.47	0.47	-0.41
Northern Ontario Wires	1	1.77	-1.84	2.72
Parry Sound Power	1	-0.47	0.47	-0.41
Peterborough Distribution	1	-0.47	0.47	-0.41
PUC Distribution	1	-0.47	0.47	-0.41
Tillsonburg Hydro	1	-0.47	0.47	-0.41
Wellington Electric Distribut	1	2.02	-1.96	0.54
Whitby Hydro	1	-0.47	0.47	-0.41
Atikokan Hydro	2	0.68	-0.55	2.54
Barrie Hydro	2	0.60	-1.06	-0.59
Brantford Power	2	-0.15	0.36	-0.62
Centre Wellington Hydro	2	0.71	-0.69	0.60
Chapleau PUC	2	-0.69	0.70	1.80
Chatham-Kent Hydro	2	-0.40	0.44	-1.39
Clinton Power	2	-0.28	0.29	1.45
Collus Power	2	-1.52	1.83	-1.92
Dutton Hydro	2	-0.73	0.84	2.63
ELK Energy	2	0.59	-0.80	-0.47
Embrun Hydro	2	-0.69	0.81	-1.01
EnWin Powerlines	2	0.47	-0.64	-1.24
Erie Thames Powerlines	2	-0.91	0.95	0.09
Festival Hydro	2	0.88	-1.30	0.24
Fort Frances Power	2	-0.91	1.07	-0.38
Grand Valley Energy	2	-1.17	1.39	-0.08
Greater Sudbury Hydro	2	0.19	-0.29	-0.06
Guelph Hydro	2	3.16	-1.49	-0.11
Hearst Power	2	-0.31	0.27	-0.61
Hydro 2000	2	-0.70	0.81	-0.64
Hydro Hawkesbury	2	-1.50	1.67	-1.17

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Labour Expense Over Expense	Non-labour Expense Over Expenses	FTE per Customer
Kenora Hydro	2	-0.64	0.45	-0.49
Kingston Electricity	2	-0.28	-0.59	-0.67
Lakefront Utilities	2	0.17	-0.32	-0.89
Middlesex Power	2	0.25	-0.37	0.86
Niagara Falls Hydro	2	-0.37	0.16	0.18
Orangeville Hydro	2	0.72	-0.75	-0.81
Orillia Power	2	-0.51	0.54	-0.09
Ottawa River Power	2	-0.12	0.19	0.31
Renfrew Hydro	2	0.59	-0.79	-0.06
Rideau St. Lawrence	2	0.97	-1.20	0.42
St. Catharines Hydro	2	1.91	-1.58	-0.49
St. Thomas Energy	2	-0.07	0.08	-0.41
Terrace Bay Superior Wires	2	-0.39	0.42	0.12
Welland Hydro	2	-0.17	0.01	-0.75
Wellington North Power	2	-0.94	0.98	0.33
West Coast Huron	2	-0.34	0.37	1.64
West Nipissing Energy	2	2.53	-2.78	0.65
West Perth Power	2	-1.36	1.63	1.00
Woodstock Hydro	2	0.70	-1.01	0.11
Aurora Hydro	3	0.23	-0.16	0.33
Enersource Hydro Mississauga	3	-0.76	1.15	-1.45
Hydro One Brampton Networks	3	1.16	-0.98	0.09
Hydro Vaughan	3	-0.13	-0.22	0.98
Markham Hydro	3	0.77	-0.90	0.50
Newmarket Hydro	3	-0.67	0.64	0.36
Oakville Hydro	3	0.72	-0.34	0.35
PowerStream	3	0.63	-0.99	0.67
Richmond Hill Hydro	3	-0.19	0.23	0.81
Veridian Connections	3	-2.37	2.21	-2.24
Wasaga Distribution	3	0.61	-0.63	-0.41

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Labour Expense Over Expense	Non-labour Expense Over Expenses	FTE per Customer
Bluewater Power	4	-0.11	-0.37	0.09
Brant County Power	4	-0.60	0.54	0.65
Burlington Hydro	4	0.87	-0.57	-0.81
Cambridge and North Dumfries	4	0.27	-0.35	-0.59
Eastern Ontario Power	4	-1.79	1.97	-0.02
Espanola Regional Hydro	4	-0.46	-0.12	-0.36
Gravenhurst Hydro	4	-0.30	0.23	-0.01
Great Lakes Power	4	0.30	-0.38	4.13
Grimsby Power	4	0.70	-0.62	-0.78
Haldimand County Hydro	4	-0.46	0.55	-0.25
Halton Hills Hydro	4	-0.17	-0.30	-0.09
Innisfil Hydro	4	-0.49	0.52	-0.87
Kitchener-Wilmot Hydro	4	1.93	-0.89	-0.15
Lakeland Power	4	0.19	-0.25	0.16
Midland Power	4	-0.58	0.43	0.76
Milton Hydro	4	0.51	-0.62	-0.34
Niagara-on-the-Lake Hydro	4	0.40	-0.99	0.40
Norfolk Power	4	1.24	-1.21	0.27
North Bay Hydro	4	-0.70	0.26	-0.63
Oshawa PUC Networks	4	0.95	-1.12	-0.56
PenWest Utilities	4	-1.64	2.15	-0.08
Port Colborne Hydro	4	-1.79	1.97	-1.67
Sioux Lookout Hydro	4	-1.21	1.53	0.63
Tay Hydro	4	-0.04	0.06	-0.15
Thunder Bay Hydro	4	1.64	-1.33	0.28
Waterloo North Hydro	4	1.33	-1.08	0.00
Hamilton Hydro	5	-1.09	0.93	-1.12
Hydro Ottawa	5	0.88	0.12	0.32
London Hydro	5	0.20	-1.06	0.80
Scugog Hydro	6	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

COMPARATORS AND COHORTS
SUPPORT SERVICES

LDC Name	Cohort	Labour Expense Over Expense	Non-labour Expense Over Expenses	FTE per Customer
Toronto Hydro	7	NA	NA	NA

Note: In standardized format, within each cohort the average value for any comparator is zero.

APPENDIX I, PART II

ECONOMIES OF SCALE AND DENSITY

Effects of Size and Density on Cost Estimated With Simultaneous Equation System

The degree to which costs rise as output increases is an important issue for electricity delivery because there is a wide dispersion in the size of the distribution companies. If there are significant scale economies, then larger firms can produce output at a lower average cost. However, distribution companies cannot directly increase output, since their role is to supply the power demanded by final customers. With the level of output of a service territory remaining fairly constant, the only alternative to obtaining scale economies is to combine operations so that a single firm takes the place of several smaller firms. However, the economies of scale obtained through mergers may give rise to various other complications that potentially negate and cancel some of the net benefits of scale.

Scale economies can be measured by the elasticity of cost with respect to output, which can be calculated directly from the cost models. Cost elasticity is the derivative of the cost equation with respect to output; economy of scale is the inverse of cost elasticity.[15] Returns to scale can be calculated at the "middle" of the sample of distributors and also for each distributor. Returns to scale can vary substantially across distributors because the inherent differences in the underlying business context and network characteristics vary in a manner that affects total cost.

When output is a simple, well-defined one dimensional commodity, estimates of scale economies—i.e., returns to scale—are easily obtained directly from the cost equations. However, for electric distribution, output can assume multiple attributes or dimensions. As mentioned in the Phase I report, output can be defined to include *electricity sales,* the *maximum rate of power delivery (kW), load factor,* the *number of customers*, and the distances over which electricity is transported (*km of lines*). Reliability is arguably another

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[15] The cost elasticity, η_Q, is the (log) derivative of cost, lnC, with respect to output, lnQ:

$$\eta_Q = \mathrm{d}lnC/\mathrm{d}lnQ \quad .$$

important dimension of output of distribution companies, though service quality data are typically not available.[16]

Estimation of the derivative of cost with respect to output to obtain the cost elasticity involves two conceptual issues: which other output dimensions change, and how do they change? Addressing these issues precipitated the inclusion of four output metrics in the analysis. While the analysis utilized electricity deliveries (kWh sales) as the primary output metric, all four metrics including load factor, number of customers served and transport distance.

In general, economies of scale are measured by "incrementing" all of the output dimensions proportionately.[17, 18] In contrast, *economies of density* involves holding some dimensions of output constant so that, in effect, more output is delivered to the same number of customers, or over the same length of line.

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[16] Data regarding service reliability are not yet collected on a consistent basis across distributors. Eventually, however, reliability data could become available and incorporated into the analysis.

[17] As presented, the equation for cost elasticity in a footnote above can be expanding to rn that

$$\eta_Q = dlnC/dlnQ \;=\; \partial lnC/\partial lnQ \;+\; (\partial lnC/\partial lnK) * (\partial lnK/\partial lnQ) \;+ \Sigma_i\, (\partial lnC/\partial lnZ_i) * (\partial lnZ_i/\partial lnQ) \;.$$

In this equation, the relevant dimensions of output are incorporated into the calculation. The derivatives involve the higher order terms of the output variables as well as the first order terms, so many coefficients are used in the numerical calculations, though they are not reported here. The partial derivatives of the variables with respect to output, $\partial lnZ_i/\partial lnQ$, are either one or zero, depending on whether the variable increases proportionately with output or stays constant. See Glyer (1990), Chapter 5.

The derivatives involve the terms of the restricted cost equation, as presented at the end of the Technical Appendix to Part I of the report. As representative of these derivatives, the partial derivative of variable cost with respect to (a single) output dimension, Q, is as follows:

$$\partial lnC/\partial lnQ_k = \beta_Q + \beta_{QQ} \cdot \ln Q + \sum_j \phi_j \cdot \ln P_j + \sum_i \varphi_i \cdot \ln Z_i + \gamma_K \cdot \ln K \,.$$

The tables in Appendix II of the Part II report present the values of the estimated coefficients. To obtain the elasticities for any particular observation, the estimated coefficients are combined with the values of the independent variables (the Z_i, P_j, Q, and K) for each of the distributors, for each year.

[18] When performing the calculations, the result depends somewhat on the manner in which the variables are specified. For example, output variables could be defined to include *customers, miles of line,* and *maximum kW served*; conversely, variables in relative form such as *customers per mile of line* and *kWh/customer* could also be included—and were included elsewhere in the cost analysis reported in the immediate report. When the variables are in "levels", to derive the scale economies, the cost elasticity increases the variable proportionately, while in the relative form they are held constant. Finally, since the analyses utilize the results of the restricted cost function, the capital stock variable, *assets*, must also be increased proportionately.

In summary, then, estimates of scale economies require that certain characteristics of output (customers/km of line, kWh/customer) be held constant. If the increase in output involves increases in the number of customers per mile of line, the result is the elasticity of density and the corresponding economies of density.

The estimated median values for cost elasticities are lower, and the corresponding density elasticities are larger, than the average values, respectively. For returns to scale and density, the values decrease systematically with increases in the level of output and customer size between the median and average values. For density economies, large differences between the median and average values are observed.

The elasticity estimates for the distributors contain a degree of uncertainty. First, multi-collinearity of the variables where the independent variables move together reduces confidence in the estimates of returns to scale, as the precision of the individual estimates is reduced, although the estimation of the cost and the error terms is not much affected. In addition, the translog function is a second-order approximation; as a result, estimates of scale economies for LDCs that are distant from the center of the overall distribution will generally have larger estimation error than for LDCs that are closer to the center. In summary, estimates of scale economies are better for distribution companies as a whole than for individual distributors. Following the summary results on the economies of scale and density is a graphical display of the estimated elasticities of total cost.

The degree of scale economies varies substantial across the LDCs since it depends on all of the second-order terms that interact with output and capital. Presented in the table below are the median and average of the estimates of scale and density.[19] The median cost elasticity is 0.82, which means that costs go up by 0.82% when output (and capital assets) increases by 1%; the corresponding average (mean) value is 0.81. This implies that the median scale economies are 1.23 and the average scale economies are 1.33. Scale economies tend to decline as firm size increases although, for the Ontario distributors, scale economies appear to be present even for the larger firms.

[19] The estimated average values of scale elasticity can be skewed by observations that data problems and, for the immediate application, the median values are perhaps the more useful and reliable of the two measures.

Table 7

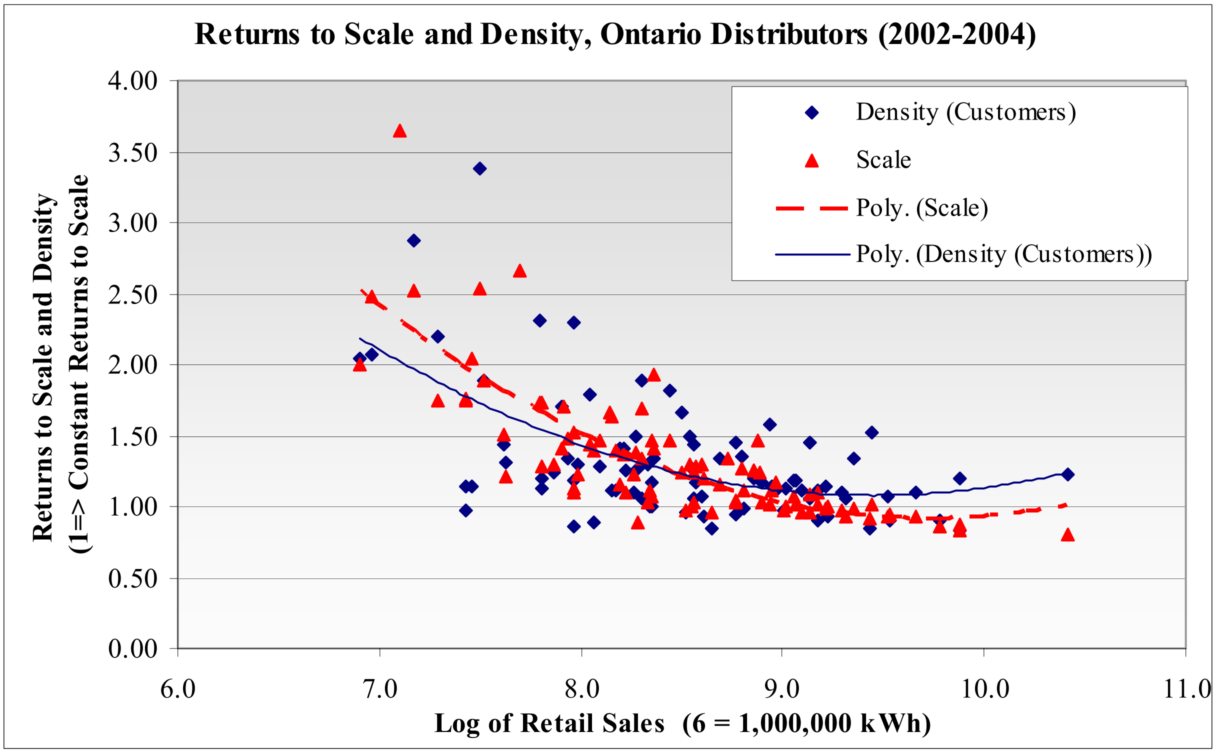
Cost Elasticities and Scale and Density Economies

	Cost Elasticity		Scale/Density Economies	
	Scale (Output)	Density (Customers)	Scale (Output)	Density (Customers)
Average	0.82	0.76	1.33	1.73
Median	0.81	0.82	1.23	1.21

Displayed in Figure 1 below are the estimates of the economies of scale and density for Ontario's electric distributors in graphical form. Most distributors have three years of data, which is used to estimate the cost equations. While estimates are obtained of each distributor for each year, shown below is the average of the estimates for the distributors over the three years.

Figure 1 reveals several outliers at low levels of output. Outlier estimates arise for two reasons. First, the approximation issue mentioned above causes estimates away from the center of the sample to be somewhat less reliable. Second, small distributors are likely to have relatively more diverse operations and estimates are potentially more affected by data inconsistencies and differences in the practice of allocation of costs among the various accounts of the Uniform System of Accounts system.

Figure 1


Returns to Scale and Density, Ontario Distributors (2002-2004)
Density (Customers)
Scale
Poly. (Scale)
Poly. (Density (Customers))
Returns to Scale and Density
(1=> Constant Returns to Scale
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
6.0
7.0
8.0
9.0
10.0
11.0
Log of Retail Sales (6 = 1,000,000 kWh)

APPENDIX II, PART II

Simultaneous Equation Model

Translog Form, Estimated with Seemingly Unrelated Regression Procedures

Labour Input Share Equation

Variables	Coefficient of the Variables	Standard Errors of the Coefficients	*t*-value when $H_0 = 0$
Comp/FTE (p1)	0.0922	0.0353	2.61
Electricity price (p2)	-0.0484	0.0213	-2.27
kWh delivered (q)	0.0030	0.0203	0.15
Gross Capital stock (k)	0.0081	0.0174	0.47
Annual Load Factor (z1)	-0.0471	0.0478	-0.99
Customers/km line (z2)	-0.0246	0.0174	-1.41
kWh/customer (z3)	-0.1267	0.0346	-3.66
Virtual Utility (0/1) (z6)	-0.3265	0.0214	-15.23
Customers/sq km(z7)	0.0105	0.0094	1.11
Share underground line (z10)	-0.0192	0.0120	-1.61
Intercept	0.4050	0.0162	25.01

Electricity Input Share Equation

Variables	Coefficients of the Variables	Standard Errors of the Coefficients	*t*-value when $H_0 = 0$
Compensation/FTE (p1)	-0.0484	0.0213	-2.27
Electricity price (p2)	0.1157	0.0291	3.98
kWh delivered (q)	0.0214	0.0136	1.58
Gross Capital stock (k)	-0.0170	0.0115	-1.48
Annual Load Factor (z1)	0.0023	0.0316	0.07
Customers/km line (z2)	-0.0089	0.0116	-0.77
kWh/customer (z3)	0.0674	0.0229	2.95
Virtual Utility (0/1) (z6)	-0.0056	0.0141	-0.40
Customers/sq km(z7)	0.0017	0.0062	0.27
Share underground line (z10)	0.0177	0.0079	2.23
Intercept	0.2318	0.0109	21.36

Complete Set of Coefficients for the Restricted Cost Equation System

Variables	Coefficients of the Variables	Standard Errors of the Coefficients	t-value when $H_0 = 0$
Compensation/FTE (p1)	0.4050	0.0162	25.01
Electricity price (p2)	0.2318	0.0109	21.36
kWh delivered (q)	0.8460	0.1024	8.26
Gross Capital stock (k)	-0.0396	0.0856	-0.46
Annual Load Factor (z1)	-0.0092	0.2766	-0.03
Customers/km line (z2)	-0.3674	0.0901	-4.08
kWh/customer (z3)	-0.4364	0.1912	-2.28
Northern (0/1) (z5)	0.0440	0.0341	1.29
Virtual Utility (0/1) (z6)	-1.1170	0.0996	-11.22
Customers/sq km(z7)	0.1004	0.0610	1.65
Share underground line (z10)	-0.0137	0.1065	-0.13
z1_z1	0.6615	0.2265	2.92
z1_z2	0.1744	0.3372	0.52
z1_z3	-0.0066	0.6245	-0.01
z1_z6	0.2147	0.4122	0.52
z1_z7	0.1970	0.1851	1.06
z1_z10	0.1279	0.2032	0.63
z2_z2	-0.0372	0.0517	-0.72
z2_z3	0.1333	0.1829	0.73
z2_z6	-0.5026	0.1139	-4.41
z2_z7	-0.0846	0.0478	-1.77
z2_z10	0.2590	0.0799	3.24
z3_z3	0.1497	0.2492	0.60
z3_z6	-0.0503	0.2601	-0.19
z3_z7	-0.0603	0.0972	-0.62
z3_z10	-0.0225	0.1432	-0.16
z6_z7	-0.1091	0.1064	-1.03
z6_z10	0.0959	0.0785	1.22
z7_z7	0.0441	0.0178	2.48
z7_z10	-0.0325	0.0516	-0.63
z10_z10	0.0049	0.0393	0.12
p1_p1	0.0922	0.0353	2.61

Variables	Coefficients of the Variables	Standard Errors of the Coefficients	t-value when $H_0 = 0$
p1_p2	-0.0484	0.0213	-2.27
p2_p2	0.1157	0.0291	3.98
q_q	0.0169	0.0786	0.22
k_k	-0.0536	0.0530	-1.01
p1_z1	-0.0471	0.0478	-0.99
p1_z2	-0.0246	0.0174	-1.41
p1_z3	-0.1267	0.0346	-3.66
p1_z6	-0.3265	0.0214	-15.23
p1_z7	0.0105	0.0094	1.11
p1_z10	-0.0192	0.0120	-1.61
p2_z1	0.0023	0.0316	0.07
p2_z2	-0.0089	0.0116	-0.77
p2_z3	0.0674	0.0229	2.95
p2_z6	-0.0056	0.0141	-0.40
p2_z7	0.0017	0.0062	0.27
p2_z10	0.0177	0.0079	2.23
p1_q	0.0030	0.0203	0.15
p2_q	0.0214	0.0136	1.58
q_z1	-0.9921	0.3098	-3.20
q_z2	0.0857	0.1394	0.62
q_z3	-0.2681	0.2286	-1.17
q_z6	0.2060	0.1145	1.80
q_z7	0.0663	0.0839	0.79
q_z10	-0.1195	0.0819	-1.46
k_z1	0.7808	0.2555	3.06
k_z2	-0.1603	0.1247	-1.29
k_z3	0.1958	0.1682	1.16
k_z6	-0.3671	0.1073	-3.42
k_z7	-0.1072	0.0705	-1.52
k_z10	0.1263	0.0710	1.78
p1_k	0.0081	0.0174	0.47
p2_k	-0.0170	0.0115	-1.48
q_k	0.0758	0.1246	0.61
Intercept	0.2843	0.0687	4.14