CAMPUT

BENCHMARKING FOR REGULATORY PURPOSES

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EXECUTIVE SUMMARY

First Quartile Consulting, LLC (1QC) and ERA, Inc. (ERA) were retained by CAMPUT in June, 2009 to work together to study the options available for using benchmarking as a regulatory tool for Canadian utilities. The two firms brought complementary capabilities to the project, making an effective team for the work. During the summer of 2009, the team conducted primary and secondary research with regulators and electric utilities to explore the use of benchmarks across the electric industry, both in Canada and abroad. This report summarizes the results of that research, and provides summary findings, conclusions, and recommendations for the implementation of regulatory benchmarks by CAMPUT members in the future.

The survey of regulators revealed that they are generally concerned with some or all of the following four key areas:

- Economic Efficiency (reasonableness of proposed investments and expenditures)
- Cost Effectiveness (prudency of costs in rates)
- Consumer Protection (reliability of the system and quality of service)
- Social and Environmental Objectives (including environment, jobs and the impact on low income customers)

Furthermore, from the **regulators' perspective** there are a number of reasons for benchmarking including: **ratemaking**, **compliance**, **audit**, **monitoring** and **reducing information risk**. This is a non-exhaustive list of some uses to which regulators could put benchmarking. Regulators are most interested in demonstrated results which will allow them to draw conclusions about performance and the relative merits of the approach undertaken by the utility.

The primary reasons from the **utility perspective** are: **performance assessment**, **target setting**, **performance improvement**, and **regulatory support**.

To assist in identifying practical approaches to benchmarking in the regulatory context, the research team surveyed the international regulatory benchmarking practices in the U.S., Australia and the U.K. The U.S. experience has provided a comprehensive inventory of information (bank of data) to be collected, compared and mined for overall observations. However, U.S. regulators have done little in the way of analysis of this information. By contrast, the Office of Gas and Electricity Markets (OFGEM) in the United Kingdom provides a mechanistic framework that includes a comprehensive inventory of information (in the form of performance metrics) that provides clear insight into utility performance, and addresses issues of compliance, audit and information risk.

Section 5 discusses a number of significant challenges to the goal of developing a standardized benchmark set for comparing utilities across Canada, as well as within individual Provinces and Territories. Some of those challenges (e.g. demographic differences) can be dealt with through the use of appropriate normalizers, peer panel selection, and good choices of performance metrics. Others will be more difficult, as information collected and the data collection process is cumbersome in the regulated environment.

Benchmarking is a process of measuring and comparing performance results in terms of quality, cost, and timeliness across organizations, to identify improvement opportunities and areas of strength, as well as to find better practices which can be adapted and implemented to improve performance levels.

There are many uses for benchmarking, and many perspectives from which to view it. Within the utilities industry, viewer perspectives might include utilities, regulators, customers, suppliers, investors, and others. Each perspective might lead to a slightly different set of performance dimensions to rank as highest in priority. Similarly, the approach to benchmarking might focus on performance outcomes, with the underlying business practices of lesser importance, or more on the processes, with the goal of highlighting improved processes which, if implemented, could lead to better performance results. Yet another variable is the question of whether to do benchmarking at strategic level, tactical level, within functions, or within very narrowly defined processes.

Each decision in developing a benchmarking protocol has to take into account these three dimensions (viewer perspective, performance/practice priorities, business "level"), and makes the selection of a particular protocol very challenging. Once those decisions are made, the difficulties of ensuring proper comparability of the companies, through consistent definitions of performance metrics and their components, present the next level of challenges to achieving a successful result. The report provides a basic roadmap for how to begin to address the many implementation issues including how metrics are affected by age and size of the system, which is just one example of how comparability of metrics will need to be assessed. The Implementation process will need to address all of these hurdles and challenges.

Before metrics can be used in ratemaking, it is prudent to understand the value of the information being collected. This will involve probing to determine if the data are in fact comparable, not only based on definitions provided but in how these definitions are implemented in the data collection process. By recommending a short list of easily available metrics, the task of data collection will not derail the launch of a more comprehensive set of benchmarking initiatives.

Although there were a number of concerns raised initially about the prospective challenges of benchmarking, the project team was able to provide a short list of initial metrics.

Customer Care	Reliability	Asset Management	Costs	Optional
• Call Centre • Billing • Customer Complaints	• SAIFI • CAIDI • SAIDI	• Asset Replacement Rates (3 year), for Distribution, Transmission and Substation assets	• Customer Care • Bad Debt • O&M (both transmission & distribution) • Corporate Services	• Safety • Line Losses • benchmarking • Conservation

These have been selected to satisfy regulators' requirements as identified in the review and analysis stage, and provide, in time, a range of potential outcomes. The data collection process we have proposed will lend itself to centralized summary and reporting that will enable establishing a national database with ranges of regional values. Preliminary data collection could consist of the few jurisdictions where data is readily available and expand over time as new regions begin data collection and reporting.

Although it may be an eventual goal to use benchmarking for rewards and penalties in the regulatory process, CAMPUT is in the early stages of data collection and analysis. It would be premature to consider applying financial implications for utilities based on an initial set of metrics being collected for information purposes.

The metrics selected were intended to provide a snapshot of utility operations and a primary comparison for information purposes. Further analysis is needed through the implementation phase to understand the implementation requirements and the role for CAMPUT. This will include, for example, exploring the value of the information, data collection costs, sources of funding, accountability for data collection and analysis, and governance of the entire data collection process. Although these are all important implementation issues, they are beyond the scope of this study. Rather than undertaking another study, the usefulness of the data can be judged by conducting a preliminary data collection to see what is available and consider what can be concluded from the information. This could be completed without the requirements of a complex process or detailed investment in infrastructure.

As the list of metrics is expanded, and the differences in utility characteristics are explored and documented, it may be possible to establish a formal set of Peer Groups. As the impact of the similarities and difference for these Peer Groups is translated into operational implications, it may be possible, over time, to begin to consider a range of standards for each metric, by Peer Group. After these standards are created, the next step is to consider factors for performance improvement.

The process will need to be documented, tested and allowed to evolve based on feedback from regulators, utilities and other stakeholders. As the data collection and analysis process matures, there will be an opportunity to begin to consider how to incorporate rewards and penalties based on these standards. However, due to the nature of the Canadian regulatory environment, the size, number and distribution of utilities, and the variations in their operating environment, it will be difficult to establish cross-jurisdictional guidelines for performance that can easily be defended in the regulatory arena.

1 INTRODUCTION

First Quartile Consulting, LLC (1QC) and ERA, Inc. (ERA) were retained by CAMPUT in June, 2009 to work together to study the options available for using benchmarking as a regulatory tool for Canadian utilities. The two firms brought complementary capabilities to the project, making an effective team for the work. During the summer of 2009, the team conducted primary and secondary research with regulators and electric utilities to explore the use of benchmarks across the electric industry, both in Canada and abroad. This report summarizes the results of that research, and provides summary findings, conclusions, and recommendations for the implementation of regulatory benchmarks by CAMPUT members in the future.

The report is divided into seven sections.

The first four sections provide background information on benchmarking, including practices in North America and other jurisdictions, as well as the views of the regulators and utilities surveyed by the project team. The information and views contained in these sections have been used as the basis for the subsequent analysis and recommendations.

The remaining sections contain the study's analysis and recommendations. Section 5 outlines potential metrics that could be used by regulators in Canada including examples of existing standards. Section 6 expands on the proposed framework and highlights some of the challenges associated with using benchmarks. The recommendations of the project team are presented in Section 7.

Additional details of the research and data collection are presented in a series of appendices that include references, a glossary of terms, interviews and survey notes along with additional information collected across jurisdictions in Canada and abroad. There are also samples of regulatory filing requirements from selected jurisdictions.

1.1 PROJECT GOALS AND OBJECTIVES

The purpose of this project was to develop a system of performance measures and benchmarks that can serve as regulatory and reporting tools to assist CAMPUT members in fulfilling their regulatory responsibilities with respect to electric transmission & distribution (T&D) utilities. In initiating this project, the CAMPUT members envisioned the possibility of evolving the reporting of benchmarking information in individual jurisdictions so that some or all of the regulators could use cross-jurisdictional benchmarking as a regulatory instrument for assessing the performance of utilities in an objective, equitable and effective manner.

The specific objectives of the project were two-fold:

- Define applications of benchmarking for regulatory purposes and identify practices and benefits for the purpose of providing comparisons to assist in regulating electric T&D utilities including rate-setting, reporting, compliance, and audit, which CAMPUT members could implement over a number of years.
- Develop a framework for the application of performance indicators and benchmark measures including reporting requirements that can be used for the purpose of comparison and regulation of electric T&D utilities.

1.2 Scope

The scope of the project includes the entire membership of CAMPUT and the electric utilities they regulate. The focus of the study was transmission and distribution and related functions within the utilities. No effort was made to investigate generation or other aspects of utilities beyond T&D, customer service, and the related management and support functions.

1.3 Approach

The project was undertaken in three distinct phases: collection of background information, analysis and development of recommendations.

Primary research for the first phase consisted of the project team gathering data and information from a wide range of individuals at both regulatory agencies and utilities. In particular,

- A survey was sent to individuals at the regulatory commissions across Canada asking about their experiences with benchmarking for regulatory purposes;
- Individuals at many of the larger utilities were sent a similar survey, asking about their experiences in the arena of regulatory benchmarking;

- Interviews were held with staff of most of the regulators in the Canadian provinces and territories;
- Interviews were held with a number of individuals at the larger utilities across Canada.

Secondary research for the first phase consisted of gathering information about benchmarking uses and applications in other jurisdictions around the world. In a few cases, this research was followed up with interviews with individuals at regulatory agencies to better understand their usage of benchmarking.

Drawing from knowledge of the various benchmarking activities the utilities are engaged in currently for their own operational purposes, the team summarized the many different existing approaches and uses of benchmarking in the industry. The uses considered were not limited to regulatory compliance. Information on the existing benchmarking activities of the regulated utilities is relevant to identifying potential performance indicators that could be implemented with minimal regulatory burden, which is one of the considerations on which the report's recommendations are based. Many utilities in both Canada and the U.S. are actively involved in benchmarking activities, with the primary purpose of improving their own performance through application of improved operating practices.

As the first step of the second phase of the work, the study team reviewed the performance indicators that are used in existing benchmark studies by the industry that would also be relevant for CAMPUT members to use for regulatory purposes. In parallel with this work, the project team identified areas of concern to regulators for which benchmarking could provide relevant and useful information in objectively assessing the performance of the utilities they regulate.

This list of possible measures that resulted from this approach was more detailed than would be appropriate for use in regulatory circumstances. Hence, the primary task in the third phase was to establish priorities within the list of potential benchmarks as a basis for recommending an appropriate and manageable list of performance measures. The first step in the third phase was to share this initial list of possible benchmarks with representatives of CAMPUT members and selected utility representatives to assist the project team to determine the information that is either currently available, or could be collected in a timely manner, and would be reasonably consistent across jurisdictions and utilities. The expected cost of providing the benchmark information was balanced against the usefulness of the candidate performance measures to rank them for implementation as cross-jurisdictional measures. The result of this process is the list shown in Section 5.

The final stage (of this third phase of the project) involved developing an interim set of results for review by the CAMPUT committee. During the course of that process, the team further developed the suggested usage of the selected benchmark metrics, and outlined a rollout approach. The results of that review and the implications are included in Sections 6 and 7.

1.4 RESULTS AND CONCLUSIONS

Benchmarking is a process of measuring and comparing performance results in terms of quality, cost, and timeliness across organizations, to identify improvement opportunities and areas of strength, as well as to find better practices which can be adapted and implemented to improve performance levels. Benchmarks may be drawn from a firm's own experience, from the experience of other firms in the industry or from legal and regulatory requirements. Although they may look at similar metrics, a distinction must be made between benchmarking and performance measurement.

Key Performance Indicators (KPIs) are business statistics that measure a firm's performance in a variety of areas. KPIs show the progress toward realizing the firm's objectives or strategic plans by monitoring activities which (if not properly performed) could result in sub-standard financial or operational performenace. In distinguishing between the two terms, which are often used interchangeably, KPIs are the individual statistics, while benchmarking is the use of these KPIs to set standards of performance expectations.

There are many uses for benchmarking, and many perspectives from which to view it. Within the utilities industry, viewer perspectives might include utilities, regulators, customers, suppliers, investors, and others. Each perspective might lead to a slightly different set of performance dimensions to rank as highest in priority. Similarly, the approach to benchmarking might focus on performance outcomes, with the underlying business practices of lesser importance, or more on the processes, with the goal of highlighting improved processes which, if implemented, could lead to better performance results. Yet another variable is the question of whether to do benchmarking at strategic level, tactical level, within functions, or within very narrowly defined processes.

Each decision in developing a benchmarking protocol has to take into account these three dimensions (viewer perspective, performance/practice priorities, business "level"), and makes the selection of a particular protocol very challenging. Once those decisions are made, the difficulties of ensuring proper comparability of the companies, through consistent definitions of performance metrics and their components, present the next level of challenges to achieving a successful result.

Although there were a number of concerns raised initially about the prospective challenges of benchmarking, the project team was able to provide a short list of initial metrics.

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These have been selected to satisfy regulators requirements as identified in the review and analysis stage, and provide, in time, a range of potential outcomes. The data collection process we have proposed will lend itself to centralized summary and reporting that will enable establishing a national database with ranges of regional values. Preliminary data collection could consist of the few jurisdictions where data is readily available and expand over time as new regions begin data collection and reporting.

2 BENCHMARKING PRACTICES AMONG CAMPUT MEMBERS

This section provides the regulators' perspective on benchmarking including why regulators are interested in adopting benchmarks as performance measures, how they anticipate using the benchmarking data, and the information that is currently collected in regulatory filings. A review of practices among CAMPUT members led to the observation that although performance metrics are seen as important and valid data to be used in assessing utility performance improvement over time, formal benchmarking is used in only a few jurisdictions in Canada at this time.

This section begins with a summary of the regulatory framework in Canada to provide (at a high level) the issues which are most important to CAMPUT members. This also provides the context for the discussion of specific regulator requirements in jurisdictions across Canada.

2.1 REGULATORY FRAMEWORK IN CANADA

As a basis for appreciating the role of benchmarking in regulatory processes, it is important to understand the tools that regulators require to assist them in meeting their goals and objectives. Regulators are primarily responsible for establishing that utilities are efficient and effective in their delivery of services but in some jurisdictions there are jurisdiction-specific issues or areas of interest that sometimes lead to jurisdiction-specific (or local) objectives.

Regulators are generally concerned with some or all of the following four key areas:

- Economic Efficiency (reasonableness of proposed investments and expenditures)
- Cost Effectiveness (prudency of costs in rates)
- Consumer Protection (reliability of the system and quality of service)
- Social and Environmental Objectives (including environment, jobs and the impact on low income customers)

These objectives are typically addressed together within an integrated regulatory framework. The first three objectives are traditional concerns of regulators, while the fourth has been added as a regulatory issue in several jurisdictions. This fourth area is an emerging challenge as regulators seek ways to effectively address these emerging requirements.

In the evolving regulatory environment, regulators are finding it increasingly necessary to focus on more than simply keeping rates for reliable power as low as possible; they must balance cost and service quality along with evolving expectations with respect to social and environmental objectives. The discussion below explores the current regulatory framework in terms of the four objectives outlined above.

2.1.1 Economic Efficiency

Cost reviews are generally conducted to establish capital and operating efficiency. In particular to address whether capital investment in new or replacement infrastructure is warranted and whether the quantum is justified. Operating efficiency necessitates an assessment of the reasonableness of costs incurred to deliver the level of service required.

For efficiency measures, regulators across Canada collect a variety of indicators to review year over year progress at the individual utility level. These are filed in rate filings and stored locally as part of the public record. At the industry level, a number of metrics exist to address these efficiencies (e.g. capital cost per new service installed, capital cost per mile of new line or of reconductored line) but they have not been reviewed in the Canadian context to determine suitability and application. Thus we are left with regulators viewing performance on a company-by-company basis. Although individual performance improvement trends can be established, there are no generally accepted standards for assessing overall performance on a comparative basis. Thus it is difficult to determine a suitable starting point or range of relevant measures.

The benefit of benchmarking, in this context, is in the ability to create meaningful comparisons across similar organizations (through established peer groups) and to establish and review trends in performance.

2.1.2 Operational Effectiveness

Regulators are also concerned with effectiveness and prudency of costs. Much of the data collected in regulatory filings focus on costs in an effort to determine if funds are being used in a manner which delivers maximum return on investment for the activities that benefit customers.

However, a review of costs compared to past performance may not be the best indicator of actual effectiveness. It only demonstrates an improvement over time that assumes a given level of performance at the starting point.

For these metrics where there are no formal industry norms for performance, the regulator is tasked with ensuring that the utility continues to meet societal expectations. This is also a challenge to evaluate in isolation. There is no clear path to establish what acceptable performance is, and looking at results from other countries or jurisdictions may be less relevant in this category.

Although numerous metrics are widely used to measure cost effectiveness, acceptable values frequently depend on local factors. Furthermore, although metric names and definitions may appear to be identical, the nature of local regulation and customer expectations may affect what is considered a reasonable and desirable outcome in local applications. It is therefore anticipated that CAMPUT members will benefit from establishing a list of metrics and compiling local results to establish acceptable ranges of performance.

Because there are operational implications associated with reducing costs, it is customary to put in place metrics to review effectiveness of performance. This may be done through the use of service quality indicators (SQIs), which generally provide standards of performance within a contract or confined group of similar utilities. This application has been used successfully under Incentive Regulation. The Ontario example, where cohorts of utilities are grouped together and ranked within a predefined range of acceptable performance, is an example of how this concept can be used by regulators. However, it is worth noting that regulators are most interested in results and would benefit most from metrics of outputs rather than inputs. A focus on results reduces the amount of data collection and review required to ensure defined objectives are being met.

2.1.3 Consumer Protection

Consumer protection extends beyond the construct of rates to focus on the public safety and reliability of the system and other similar performance objectives (customer care). This is particularly relevant when we consider the trade-offs between cost and performance, while continuing to maintain a focus on customers.

In the area of customer care, for example, metrics can be developed for average hourly, daily, weekly or monthly performance. As the level of granularity increases, so too does the cost of delivery. A call centre that is required to deliver a KPI hourly will have higher staffing requirements to ensure that it is met every hour of every day. By measuring at that level, performance is guaranteed. The question becomes, is this the desirable level of performance or should the metric be designed to reflect a different result?

Consumer protection also includes addressing customer concerns or complaints with customer care and billing and other service quality. It might also include access to power for remote locations and distribution of rates across class. This last concern ensures that residential customers, in particular, are not subsidizing commercial or industrial energy rates. In general, if regulators are successful in addressing issues of efficiency and effectiveness, consumers will be protected from their biggest concerns.

2.1.4 Other Local Regulatory Objectives

The final area that was identified by CAMPUT members as relevant to their responsibilities was various other objectives that are jurisdiction specific (regional). These include environmental considerations, conservation targets, social policies to support low income customers or a push for more use of local renewable power. Although these may on the surface seem unique to each jurisdiction, it is important to determine what types of local objectives exist in each jurisdiction. This will then allow for an understanding of what, if any, regional requirements may apply beyond individual local jurisdictions. With an inventory of local objectives, collecting data on a select set would allow regulators to determine if individual targets can be turned into regional objectives, which could then be translated into standards or performance benchmarks.

Although metrics in this area may not apply immediately to all jurisdictions, CAMPUT members acknowledge that these types of metrics are important to monitor. This could evolve to include a periodic review of emerging benchmarks. With an inventory in place, CAMPUT could monitor the relative importance, among members, of these emerging objectives ultimately leading to an enhanced list of benchmarks.

2.2 PERSPECTIVES OF THE REGULATORS

2.2.1 SCOPE OF REVIEW

A series of interviews were conducted with representatives from the provincial and territorial jurisdictions across Canada. The National Energy Board was also included to provide the federal perspective. A list of CAMPUT members that were interviewed is included in Appendix F. The purpose of the interviews was to:

- Develop an understanding of the type of data that is currently being collected and how it is being used; and,
- Determine how benchmarking data could be used in future regulatory filings.

The review was intended to identify, compare, and document the existing practices amongst CAMPUT members related to benchmarking from a regulatory perspective.

In general, our study found that benchmarking is only conducted in a limited number of jurisdictions in Canada, and even where it is used, its purposes are in many cases limited. Most regulators are interested in reliability metrics. Where performance metrics are collected for LDCs, they are generally internal year-over-year comparisons. These results are shared with regulators either formally (through rate case filings or made available through interrogatories) or informally (during regular review sessions). Most regulators were satisfied with both the quality and transparency of the information provided.

An overview of regulatory policy across Canada identified the beginning of a shift in regulatory philosophy. In the past, the primary focus was on delivering the greatest value to customers. Regulators were most interested in service reliability and reasonable prices. The mandate is evolving to focus more on social policy, encompassing such areas as energy efficiency, climate change and energy poverty. Although the mandate has not formally changed in Canada, these shifts are now very evident in the United States. This may contribute in part to the 'Crown Corporation Dilemma' which will be further explored in Section 6.

2.2.2 REGULATORS' PERSPECTIVE ON THE IMPORTANCE OF BENCHMARKING

Many regulators identified that additional information on relevant performance metrics could help provide a valuable comparison point for the information they receive from the utilities they regulate. Benchmarking is seen as a way to create value to regulators whose mandate is focused on serving and protecting the public interest. In considering the use of benchmarking for regulatory purposes, many regulators were concerned that they did not have adequate measures of utility performance. Although information is presented in regulatory filings, without a context to determine or frame the understanding of what is reasonable, it is difficult to judge the appropriateness of proposed activities.

One of the key reasons that a regulator may want to use benchmarking for regulatory purposes is to streamline the process of regulating the costs incurred by utilities. Regulators protect the public interest by ensuring that a utility's revenue requirement is just and reasonable and its service and reliability standards are adequate. By establishing a consistent reporting metrics, the regulator is able to assess a utility's performance trends over time to determine anomalies in results and identify areas for further probing.

In addition, without a peer group or established set of norms, it is difficult to gauge the overall performance level of a utility. Although a utility may be seen to improve year-over-year performance, it is possible that the starting point for comparison is considerably better or worse than like utilities in other jurisdictions. Without some form of comparative data, regulators are disadvantaged in their assessment. When the regulator is able to compare performance on certain key metrics within a peer group, it is easier to identify variances in performance trends over time, allowing the utility the opportunity to explain why its particular performance on given metrics may be different from industry norms or peers. For example, cross-jurisdictional benchmarking among CAMPUT regulators could serve as a reasonable basis to determine if and how the OM&A and CAPEX for a given utility are justified.

Regulators see the value in benchmarking to understand the performance of the utility. The introduction of additional reporting would provide some comfort that information risk has been reduced. Where formal reporting is in place for audit or compliance purposes, having a clear understanding of the range of appropriate values further enhances the quality and transparency of the information being presented.

More information on individual jurisdictions' views on the value of benchmarking can be found in Appendix F.

2.2.3 INFORMATION AVAILABLE TO REGULATORS

In order to assess the ability to create a series of benchmarks for application among CAMPUT members, it was important to identify what types of information are available to regulators today and how they might consider using the information in future. A review of performance measurement efforts across jurisdictions in Canada identified that only a handful of jurisdictions where regulatory bodies were currently considering benchmarking. These regulators are both interested and aware of the issues. They have put in place processes for data collection and formal filing requirements to ensure the data is captured as part of the ratemaking process.

This does not mean that information is not available in other jurisdictions. Performance measurement is about collecting data. A great deal of information is available through the standard regulatory filings submitted to regulators today. Table 1 below identifies the type of information that is available, by jurisdiction across Canada, allowing for a preliminary list of reasonable metrics. All regulators have access to cost data, including both CAPEX and OPEX. Most have instituted the collection of reliability data like SAIFI, SAIDI and CAIDI based on the Canadian Electrical Association definitions.

Table 1: Data Availability and Use, by Jurisdiction

Jurisdiction	Data Available from Regulatory Filings	Areas of Interest	Potential Uses of Benchmarking
British Columbia	• Financial (Net Income, ROE, ROA, EBIT Interest Coverage, • Debt to Equity Ratio) • OPEX, CAPEX • Reliability (SAIDI, SAIFI, and CEMI-4) • Safety (Injury Severity Rate and All injury frequency) • Customer Satisfaction (CSAT Index 4, Billing Accuracy, First Call Resolution) • HR (Vacancy rate, Employment engagement) Metrics are reported for distribution and transmission	Operating and capital costs, customer care and system reliability	Audit Focus is on overall performance and year over year improvements in results

Table 1: Data Availability and Use, by Jurisdiction (Cont'd)

Jurisdiction	Data Available from Regulatory Filings	Areas of Interest	Potential Uses of Benchmarking
Alberta	• OPEX and CAPEX • Reliability (SAIDI, SAIFI, Worst-Performing Circuits) Customer satisfaction • Meter reading • Telephone service • Worker Safety • Work completion Metrics are reported for distribution and transmission	Commission preparing to review productivity measures; maintenance efficiency; not financial benchmarking – difficult to collect and report; finding suitable comparators based on regional economic differences	Efficiency Used for Customer Care and Maintenance in two recent decisions (operations only); measuring efficiency of utility against Canadian average; cautions that financial benchmarks require interpretation
Saskatchewan	• OPEX • Assets • Reliability (SAIDI and SAIFI) • Customer Satisfaction	Customer care, rate schedules, operating costs, CAPEX amortization, DSM, IFRS implications, operating costs, rate of return and debt/equity; Climate Change	Efficiency Focused on input assumptions, provide tools for comparison and the ability to consider range of values
Manitoba	• OPEX • Asset Data • Safety • Customer Service • Reliability (SAIDI and SAIFI) • Financial • Customer Service	TBD	New Chair to be announced January 2010
Ontario	• Cost (Capital and O&M by function) • Reliability (SAIDI, SAIFI, CAIDI) • Service Quality (connections of new services, telephone service, appointment scheduling, emergency response)	CDM; environmental protection and greenhouse gases; new focus on social and environmental policy, facilitating government policy; nature of service territory (urban vs. rural) and impact on performance; currently have established cohorts	Efficiency and Ratemaking Use as a tool to facilitate cross jurisdictional comparisons to test evidence and reports presented during rate setting process; reasonableness of performance using comparable, meaningful and quantifiable metrics

Table 1: Data Availability and Use, by Jurisdiction (Cont'd)

Jurisdiction	Data Available from Regulatory Filings	Areas of Interest	Potential Uses of Benchmarking
Ontario (cont'd)	Metrics are reported for distribution and transmission		of efficiency; transparency through definitions and the ability to interpret/understand the story; establish standards as part of license requirements
Québec	• Costs (distribution, customer service, operating) • Assets, net fixed assets, CAPEX • Reliability (SAIFI, SAIDI) • Telephone service • Meter reading • Security (employee and public security) • Customer satisfaction Metrics are reported for distribution and transmission	Prudency and cost of new investments; cost of energy efficiency and climate change initiatives recommended by other Boards	Evaluation Analysis tool for cost of service; filed in rate case with analysis of results
New Brunswick	• Costs, Assets and Customers	Service quality, system reliability, environmental stewardship and safety; balancing environmental and economic impacts	Audit Confidential Benchmarking study for Business Plan purposes
Nova Scotia	• Reliability (outage performance index) • Cost Metrics (Capital and O&M by function) • Customer satisfaction	Reliability and Executive Compensation; Climate Change, DSM and Renewables	Audit One of many information sources that could be used; need evolutionary process to move from year-over-year comparisons to across companies and jurisdictions

Table 1: Data Availability and Use, by Jurisdiction (Cont'd)

Jurisdiction	Data Available from Regulatory Filings	Areas of Interest	Potential Uses of Benchmarking
Prince Edward Island	• Financial • OPEX • Net Fixed Assets • Customer service (telephone service, appointment scheduling, meter reading, service connections) • Reliability (SAIDI, SAIFI, CAIDI, Voltage Performance) • Worker Safety	Climate Change; management costs relative to other utilities; CDM	Audit Comparison that is simple (ranges); not extensive or expensive regulatory process
Newfoundland and Labrador	• Operating costs • Assets • Reliability (SAIDI and CAIDI) • Worker safety • Customer care (telephone service, meter reading, direct customer work)	Reliability, financial, operational and customer care performance – quality and transparency of results; climate change as emerging government issue	Audit Benchmarking reports filed to identify range of possible values and ensure performance is reasonable; no plans to use for any other purpose
Yukon	Yukon Energy Corporation was required to file in its next GRA, KPIs for each of the functions included in the application	Reliability, health and safety, compensation and staffing/vacancy assumptions	Evaluation Source of information to compare range of results to gauge reasonableness of current performance; provide framework for additional comparisons
Nunavut		Reliability, operating and administrative costs; capital expenditures	Audit Potential to select a few key comparators and include in regulatory filings
Northwest Territories		Compensation, operating costs and line losses	Evaluation Currently available information to be viewed in the context of range of results achieved in other jurisdictions

All regulators conduct an operational review that includes some discussion of asset management practices. Although customer care is important, there is a wide range of difference in the information provided. For utilities that have opted for outsourcing, there are detailed service level agreements in place. A broad range of metrics are provided to regulators to assess the effectiveness of the service and the benefit to customers of the outsourcing option. For those who have chosen to maintain in-house customer care, the level of detail is more limited, but it is possible to create metrics on the cost of each option and a high level view of effectiveness in meeting customer expectations.

Most regulators identified no plans to introduce formal benchmarking. Any current data collected is to ensure prudent performance and reasonableness of both costs and results. Appendix E provides a comprehensive view of the information collected as part of the regulatory filing requirements in each of the jurisdictions in Canada. This was used, in part, to help address which metrics could be included in the short list presented in Section 5.

2.2.4 Regulators' Current Uses for Information

Most regulators interviewed identified that benchmarking would be used in either audit or evaluation to gauge the reasonableness of the results provided. This information is currently viewed in isolation. Many regulators have access to past year and future year data in regulatory filings which provides a view for actual and forecast results over a small window, but may not be sufficient to conduct any meaningful trend analysis. With a national data inventory, and multiple years of data on specific metrics, the value of the information provided will be enhanced. Even if regulators are hesitant to use it formally in regulatory proceedings, it will be valuable as an additional source of reference data.

Once all this information is housed centrally in a national data inventory, it is fairly simple to begin compiling and creating a series of ranges for standard performance. These could be based on provincial groupings (for those areas which have multiple utilities), geographic groupings (reflecting regional values for utilities with potentially like characteristics), or size groupings (to reflect the differences between large and small utilities). Regardless of the Peer Group divisions, the first step is to identify metrics and begin collecting data.

However, it is not only the information that comes from the data itself that provides value. The additional information collected about utility operations can provide some context to begin exploring best practices across utilities in Canada. For example, when applying SAIDI as a benchmark measure to review the reliability performance of a particular utility against cohorts, the regulator can better understand the performance of the utility against similar utilities if it has the knowledge of “common approaches” and “common practices” behind reliability performance in other jurisdictions. The range of values provides quantitative information, and the practices themselves create a qualitative framework.

An appreciation for the range of values, and how utilities can be combined into Peer Groups will also help regulators to develop a more comprehensive view of the relative performance of individual utilities.

Section 2 has summarized some of the key findings of the data collection exercise. Appendix F includes detailed interview notes, and a summary of answers to the questions posed by the CAMPUT Working Group. It also provides a listing of the questions used in interviewing regulators, along with a table listing the individuals who were interviewed.

3 APPLICATIONS OF BENCHMARKING FOR REGULATORY PURPOSES

This section identifies how CAMPUT members can use benchmarking in Canada. It parallels the requirements of the regulators, with the value to utilities. While at first blush the difference seems significant, this section acknowledges that differing rationales for data collection may still benefit from a similar set of metrics.

3.1 HOW REGULATORS USE BENCHMARKING

Many regulators identified that they had not spent much time focusing on the value of benchmarking, but were interested in viewing the possibilities of establishing performance metrics for electricity transmission and distribution utilities across Canada. For those who had spent time considering the value of benchmarking for regulatory purposes, four reasons were presented for why this information would be valuable.

From a regulator's perspective there are a number of reasons for benchmarking:

- **Rate-making** – to assess the validity of the information presented and used to set rates; address concerns about information risk and ensure that utilities are performing as efficiently and effectively as possible. Benchmarking provides valid comparison points across similarly performing utilities.
- **Compliance** - to ensure that a utility is compliant with regulatory requirements. This may involve assessing whether the utility meets the requirements of accepted practices, legislation, rules and regulations in the form of specific standards or the terms of a contract. Benchmarking can be used to identify the validity of an approach, and best practices from other companies in the industry.
- **Audit** – to support the financial and operational review of utility performance including a systematic review and verification of results. Benchmarking provides standard definitions of performance and expected results.

- **Monitoring** – to determine Utility Accountability (delivering performance to customers), Individual Utility Efficiency Assessment (delivering value to ratepayers), and Utility Industry Efficiency Assessment (performing within the range of acceptable values for the industry). Benchmarking in this context is for data collection and to help establish a range of acceptable values or identify areas that require additional review.

- **Reduce Information Risk** – to mitigate the risk associated with the imperfect and incomplete information that regulators must rely on in making regulatory decisions; benchmarks can provide an independent check on the reasonableness of the information available to regulators.

Regulators are most interested in demonstrated results which will allow them to draw conclusions about performance and the relative merits of the approach undertaken by the utility.

3.2 HOW UTILITIES USE BENCHMARKING

Utilities have collected individual KPIs and participated in benchmarking studies to help them gauge performance, identify areas for improvement, explore industry best practices and fulfill corporate objectives. This proactive activity is designed to help them improve their own performance, and is a very positive thing for them to be doing. The information has typically not been developed as part of regulatory proceedings, and is ordinarily not provided to regulators, although when asked, the utilities have provided copies of their benchmark reports to their regulators.

From a utility perspective, there are also four primary reasons for benchmarking.

- **Performance Assessment** – On either an ongoing basis, or on a periodic basis, companies want to be able to compare their performance levels against their peers, in order to understand where they have strengths, and conversely where they have significant improvement opportunities. In studies where this is the case, typically focus is on performance metrics and outcomes. Depending on the level of depth of metrics covered, the studies can provide general, overall-level help, or detailed, very specific information about narrowly-defined operating areas.

- **Target-setting** – Benchmarking is often used to help set targets for future performance, based on current performance and the performance of peer companies. The benchmarks provide a helpful frame of reference as to what is possible and/or reasonable for an individual company

- **Performance Improvement** – For companies looking to make significant performance improvements, the practice side of benchmarking is very helpful. Performance improvement efforts often include a component of study of best practices, to find new and better approaches to adapt and apply at the home utility. Certain of the industry-wide benchmarking efforts have a focus on best practices, and most of the individual-company initiatives focus on practices.
- **Regulatory Support** – Over the past 20 years, it has become clear that companies who are looking for particular outcomes in a regulatory proceeding can support their case by providing benchmarks of performance showing where they stand versus their peers. It is also helpful for the regulators, for the same reason – there is a more logical, justifiable basis for their decisions on rates, service level targets, etc. when comparative results are available.

Utilities typically focus on performance and opportunities to enhance it. A broad range of KPIs are collected to ensure that problem areas can be dissected to diagnose the cause of the performance shortfall.

3.3 FINDING COMMON GROUND

In defining the two views as above, it is easy to see that there are more similarities than differences between the way benchmarks could be used by regulators and utilities.

Table 2 on the following page provides a comparison of how regulators use performance measurement information and/or benchmarking information. This comparison shows that significant common ground exists since both utilities and regulators are concerned about closely related performance issues. Both work to ensure the most prudent use of resources to deliver quality service at a reasonable price.

Table 2: Comparing How Regulators and Utilities Use Information

Regulator Perspective	Utility Perspective	Rationale for Use and Implications
Ratemaking	Regulatory Support	Some regulators currently require utilities to provide information to support their revenue requirements and other proposed investments in their infrastructure; Utility may choose to provide additional data in the form of a benchmarking study sponsored to further support their submission and demonstrate ranking within Peer Group. Regulator challenge is that there is no process by which to gauge the validity of the data provided and the significance of the comparison case. This could be addressed with benchmarking and cross-jurisdictional comparisons.
Compliance	Performance Assessment	Regulator requires utilities to present data to support compliance with legal or regulatory obligations; Utility uses KPIs to assess performance and diagnose areas for improvement which includes compliance for those areas where specific metrics have been established by regulator. With clear understanding of requirements, definitions may vary for the broader set of KPIs, but in time the two objectives can be brought together allowing regulator to have more visibility into broader performance of utility.
Audit	Performance Improvement	Regulator requires utility to submit to regular auditing of operational and financial results to ensure prudency of expenditures; Utility conducts regular reviews and internal audits to improve performance in areas that are not meeting expectations or falling short of proposed targets/consistently over budget, benchmarking assists by introducing best practices. Regulator would not need access to detailed audit information in areas where results are acceptable, or risk is reasonably low. Additional information may be requested when performance does not meet expectations or where risks are perceived to be sufficiently high that consequences are not acceptable. The challenge here is that this additional level of detail is generally confidential and could not be made available for broader review and analysis. However, benchmarking high level KPIs against industry standards would clearly identify subpar (or superior) results and lead to an informal or confidential assessment of reasons. A review of best practices would also assure regulator that all efforts have been undertaken to improve performance.
Monitoring	Target Setting	Regulator requires transparency in reporting to further understand and be able to diagnose shortfalls (and excellence) in performance – ability to view performance over time and make in-kind and cross-jurisdictional comparisons; Utility uses benchmarks to establish reasonable targets for internal process improvement based on the results of Peer Groups. As per audit above, challenges result from sharing of confidential information and also in the nature of reporting. Even if data could be shared, it would be difficult to agree on a common reporting structure for all metrics. This is where selecting a short list of key metrics is essential to success of any proposed benchmarking efforts.

Each of the comparisons areas in the table above, the comparison is intended to draw parallels without suggesting that the purposes are the same. Rather the parallels are intended to suggest that both functions may sometimes use and interpret similar data.

A regulatory framework for benchmarking that is results-based will ensure that regulators can gauge reasonableness of the values presented and ensure confidential information is not being shared publicly. However, there are many difficulties and challenges associated with benchmarking, many of which are identified in the report and will need to be addressed before effective comparisons can be established.

4 OVERVIEW OF BENCHMARKING PRACTICES

In undertaking this review, CAMPUT members anticipated insight could be gained by examining what regulators in other countries have proposed and considering how to transfer the international experience to Canada. This section outlines North American and international benchmarking activity. The review of broad-based and niche studies provides a selection of approaches for data collection and review. Three unique jurisdictions were reviewed to provide examples. Australia and the United States are included as examples of countries with a large number of state or regional regulatory bodies. Similar to Canada, the geography is vast and there are a number of different utilities of various sizes and structures. The United Kingdom is included as an example of a jurisdiction where benchmarking is practiced formally. In Australia, utilities are moving to national regulation to address variations in regional control and expectations, while the information from FERC and OFGEM includes details of regulatory filing requirements.

The final discussion provides CAMPUT members with lessons learned from these jurisdictions and a view to how these structures could be applied in Canada.

4.1 NORTH AMERICAN BENCHMARKING ACTIVITIES

There are a variety of benchmarking activities in place for utilities in North America. These range from broad-scale industry studies to very focused single-utility efforts. Most are entirely voluntary, and the utilities pick and choose which ones they might want to participate in based on the focus of the study, structure of the approach, and cost in terms of both resource requirements and fees to participate.

Essentially there are two major aspects to benchmarking – performance measures and practices. Some benchmark studies focus on the performance metrics and outcomes, and some focus on the practices, in search of the "best practices". Still others combine both practices and performance measures. The benefits depend upon the purpose for the benchmarking effort.

The regulator's perspective is to serve and protect public interest and therefore key reasons to benchmark focus on making sure that there is an appropriate frame of reference for decisions around rates and service levels, and a mechanism for holding utilities accountable for delivering performance for their customers in line with the costs of providing the service. Typically the focus is on metrics and performance outcomes, rather than on the underlying practices that drive the performance levels.

Utilities use benchmarking to assess performance and identify areas for improvement. They tend to be focused on the underlying practices that will help diagnose performance shortfalls, and provide areas for improvement. Benchmarking has also proved useful to support regulatory rate filings by demonstrating where the utility stands relative to other similar service providers.

With that background, there are a number of different types of benchmark studies extant in the North American utility industry, with different reasons why companies participate in them. We provide a summary of some of the most well-known studies below, as well as descriptions of some of the individual-company efforts that occur on a regular basis. Although these are studies that are funded by utilities, they provide the background for the types of information that are available and how it is being used. It will also provide a structure or framework for using the data to be collected by CAMPUT members.

Below is a summary of a few sample study formats. Additional detail on these current benchmarking studies can be found in Appendix C.

4.1.1 BROAD-BASED INDUSTRY STUDIES

This type of study is characterized by a large number of participants, typically with a broad scope of subject areas covered (e.g. all of transmission and distribution), run on an annual basis, and covering both metrics and practices. The different studies have different areas of concentration, but several of them cover similar subjects. We list the largest and most well-known of the studies below.

First Quartile Consulting performs large-scale studies on an annual basis, with participants from Canada and the U.S. Those studies cover both performance and practices, and are very broad-based, both in terms of the number and types of utilities who participate and in terms of the level and depth of the coverage for the operational areas covered. There are three studies – an Electric Transmission & Distribution study, a large-utility Customer Service study, and a Customer Service study run for the American Public Power Association members, which are typically smaller utilities. These studies have become industry standards for measures of both cost and service levels, as well as a means for companies to continually keep up with the latest practices in the industry.

The Canadian Electric Association for the past 15 years has run a series of benchmarking studies across the Canadian electric industry. Most of the large utilities participate in the annual studies, along with some of the smaller utilities. Of interest for this project is the studies run in the areas of Transmission, Distribution, and Customer Service. CEA also covers other subjects in parallel studies each year. These studies are well-structured, with strong definitions of cost and service categories, along with reasonably good data validation mechanisms.

PA Consulting, through companies it acquired in 2000, has run studies of electric T&D and utility customer service for 20 years. The studies were the leading industry benchmark studies prior to when PA took them over. In the past few years, these studies, while still comprehensive for the functional areas covered, have lost participants to the other studies available in North America.

4.1.2 CROSS-INDUSTRY STUDIES

A wide array of studies exists throughout the industry for comparison of performance and practices in specific functional areas. These studies tend to be cross-industry, and the scope can range from very narrow to extremely broad. Utilities participate in some of these studies, although they tend to prefer to participate in studies where the primary participant base is other utilities. Some of the studies are done through associations, others are performed by consulting firms, and the fees vary from very low to very high. Examples of these studies are included in Appendix C.

4.1.3 NICHE-FOCUSED STUDIES

There are a number of very narrowly-focused benchmark studies that utilities in North America participate in on a regular basis. They have different purposes, different research approaches, and different levels of publicity/notoriety regarding the results. The two examples identified below demonstrate the importance of these limited scope studies,

One area of large-scale benchmarking activity for distribution utilities is vegetation management. Trees tend to cause a large percentage of the service interruptions for most utilities, and the activities necessary to manage the trees to prevent interruptions is typically one of the very largest cost items in the operating budgets. Companies use these services as a means of improving their own vegetation management operations, and to support regulatory proceedings.

J.D. Power performs customer research, to understand the perceptions of customers about their utility service providers. The studies are done across North America, and feature multiple dimensions of satisfaction. The studies are of a uniform (minimal) depth of research for large utilities whose customers are solicited for their opinions. This study is the closest to a comprehensive mechanism for comparing customer satisfaction across companies.

4.1.4 Small Group Studies

There are a number of small utility associations and consulting firms who provide benchmark studies in the utility arena on a regular basis. The utility-based ones have grown over time from a few companies wanting to study specific areas to a regularly-scheduled set of studies performed on an annual basis, with a rotating series of subjects that are covered. These studies tend to draw participation on the basis of the level of interest in the particular subjects under study for the year.

These studies tend to focus on performance outcomes and practices in support of performance enhancement. Companies typically participate to learn about best practices to support continuous performance improvement objectives. A sample of these studies is included in Appendix C.

4.1.5 Individual-Company Initiatives

Every year, individual companies who are working on performance-improvement initiatives lead their own benchmark/best practices studies, designed to support their own initiatives. These studies typically begin with some broad comparisons of publicly-available performance data, and then focus in on a few companies who are performing well in the area(s) of interest. They then investigate the practices in place at those top-performing companies, to find practices they can adapt for use in their own unique environment. At any given point during the year, there may be dozens of such studies going on across North America, with a constantly changing cast of study performers and participating utilities. The focus of these studies is most often on performance improvement.

Utilities use these studies to support outsourcing contracts, to determine appropriate fees and service levels. Highlights of the use of benchmarking in the B.C. Hydro outsourcing of customer care to Accenture, is included in Appendix C.

4.2 BENCHMARKING IN OTHER REGULATORY JURISDICTIONS

Different jurisdictions around the world have a variety of different approaches to benchmarking from a regulatory perspective. Some have begun to use benchmarks on an experimental basis to create targets for specific metrics, while others have had benchmarks in place for a number of years, and are using them for large portions of the ratemaking process. Most often, the benchmarks are used to drive targets for appropriate service levels

Where specific service level targets are involved, the most frequent uses are typically in setting the targets, identifying reasonable "bands" around the targets, and then building a set of penalties (and more rarely, rewards) for performance around the targets. In many jurisdictions today, there are reliability targets which companies are held to, with penalties for failure to achieve the targets. These targets are set by a combination of past performance of the individual utilities and performance within a panel of peer utilities. To the extent that a true peer panel of utilities can be identified and used, the regulators can simply compare the entire panel against each other, and create rankings within the group.

The U.K. is an example of formal benchmarking for a small number of relatively homogeneous utilities. The applicability of the U.K. model in Canada will be further addressed later in the report. It is worth noting that a number of the utilities contacted through the course of our research voiced concerns about applying the U.K. model in Canada.

In contrast to the Canadian situation, the U.K. has a limited number of very large utilities, all of which were originally built using the same system design standards. There are no significant differences in system configuration. Further, they are all subject to essentially the same weather patterns, with the exception of London Electric, they all have similar customer density, and they all operate under exactly the same regulatory regime. All of these factors make the U.K. a very easy market to apply uniform benchmarks against, without having to factor in the very different demographic circumstances found in Canadian utilities. OFGEM does not need to address the demographic differences among the utilities, because they are not significant. Canadian regulators certainly cannot ignore the demographic differences among the utilities in performing any appropriate benchmark comparisons. However, with a focus on results, many of these concerns can be mitigated because the input value becomes less important than the output of the activities being monitored.

4.2.1 Generalized Reporting Requirements: the United States Experience

In the U.S., the major investor-owned utilities (IOUs) are required to report a lot of financial and accounting data to the Federal Energy Regulatory Commission (FERC). FERC has established and maintained a "uniform system of accounts" which outlines what costs go into each category, and the companies report against that. The companies report in a FERC "Form 1" for electric utilities and "Form 2" for gas utilities, for a lot of detailed categories of costs and other operational data.

The Form 1 reports also include a substantial amount of data about the utilities' electric systems, including such statistics as miles of line, voltages, numbers of customers by various types, etc. The data thus allows at least a modest level of statistical analysis including making appropriate adjustments for some demographic variables. An example FERC Form 1 is provided as Appendix H to this report. The example is the 2008 year-end report for NSTAR, who serves a territory in and around Boston, Massachusetts, but it could have been any other IOU.

In the U.S., the municipal and cooperative utilities also use a modified form of the FERC uniform system of accounts, and provide data in much the same categories. In recent years, the requirement for filing these reports has been relaxed, but many of the municipal and cooperative utilities still track costs according to the "uniform system of accounts", so that comparable data can be gathered and analyzed.

Many utilities in the U.S. utilize the data provided to FERC in the Form 1 and Form 2 reports for their own purposes. These purposes include assessing their own performance in comparison to their peers, setting improvement targets, and finding peer companies to contact for discussions regarding operational practices. Individual FERC Form 1 reports can be downloaded from the FERC website, and entire databases containing the data from all the utilities who submit the form can be purchased from vendors who assemble them from the individual company filings. Regulatory staffs have access to the same information.

There is no national equivalent in Canada to the FERC uniform system of accounts for utilities that is truly utility-specific. Although select jurisdictions, like Ontario and Alberta, have established Uniform System of Accounts (USoA) that have been in place for many years for both gas and electricity companies, these are not consistent across all regulatory jurisdictions. General accounting rules apply but differences in the specific categories of costs across jurisdictions may lead to some difficulties in making effective comparisons.

In the U.S., FERC has jurisdiction over the interstate transmission of energy. In so doing, it has responsibility for transmission rates and operational performance in interstate transmission. At the distribution level, jurisdiction for setting rates falls to the state regulators. FERC collects comprehensive data on utilities, but other than reviewing for overall performance, very little formal review or analysis is conducted at the distribution level. In fact, FERC does not acknowledge use of any formal benchmarking; their mandate as a national agency is the collection and reporting of data. Any analysis would be conducted regionally or by individual utilities which may choose to use the data available to support their own results.

In approving the transmission rates for individual utilities, FERC does not require any particular use of benchmarking information. Some transmission providers have chosen to use benchmarks as part of their filing documents, just as some distribution providers have done in ratemaking proceedings before state regulators, but it is not a requirement to do so.

FERC oversees an array of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) across the U.S. As part of that responsibility, FERC requires the RTOs to report an array of information about operations and costs. The information collected is assembled into Operating Report Cards, containing the following categories of information:

- Cost Management
- Business Processes
- Market Operations
- System Operations
- Corporate Governance/Stakeholder processes
- Corporate Strategy/ Performance Measurement

- Stakeholder Satisfaction

On the operational side, transmission operators in the U.S. are required to report reliability data to the North American Electric Reliability Corporation (NERC). In the past 10 years, NERC has refined its standards, and beginning in 2008, all transmission operators are required to report detailed reliability statistics to NERC in accordance with the new standards. These standards require reporting on the performance of each transmission circuit. In the period of 2005-2007, the companies were encouraged to set up tracking mechanisms for reporting, so that they would be fully prepared for the reporting requirements in 2008.

The new NERC reporting requirements have created a need for the companies to establish tracking mechanisms and assign people the responsibility of overseeing the tracking and reporting of the information. In a recently completed study by First Quartile Consulting, each of the responding companies indicated at least a modest increase in staff requirements in order to comply with the reporting requirements. The fact that there are compliance audits and significant penalties for failure to report has ensured that all the companies have made substantial efforts to comply.

4.2.2 Understanding Information Risk: the Australia and New Zealand Experience

Australia does not practice formal benchmarking as a regulatory requirement, but regulators have put rules in place, and identified certain key performance indicators to address the issue of "Prudent Expenditure". Like many North American jurisdictions, regulators are focused on ensuring ratepayers receive reliable service at reasonable cost. A review of utility practices is currently underway in Australia, with regulators looking to understand what benchmarking is currently in place among different regulated utilities. The interviews have focused on:

- What is currently being measured and the process used to do so;
- The amount of information available and how long utilities have been collecting data; and
- An assessment of whether the facts available support the position presented in rate filings.

Since reviews of performance metrics have been in place for some time, the regulator is fairly confident of the way that the utilities are going about justifying their costs in their rate cases. As a result, the regulator has stepped back a bit and now looks at submissions based on the track record of each participant. More importantly, utilities are now getting a lot more sophisticated about how to build justifications for larger scale changes (e.g. substantial asset replacement programs, smart meters, etc). This is in keeping with a results-based regulatory framework.

A recent focus has been on reliability, which has been brought out by a number of high profile outages. With an aging infrastructure, large geographic areas and a long focus on keeping rates low, regulators are beginning to focus on maintenance and asking if the utility is spending enough. Asset management has become a priority area in more recent rate cases. Historically, rate case reviews have been driven by issues of cost and rates, with an understanding that large rate increases would not be desirable. Limiting rate increases resulted in much-needed maintenance work being set aside with predictable consequences.

Although formal benchmarking is not practiced in Australia, much like most jurisdictions in Canada, transmission companies are asked to submit their proposed capital expenditures into standard templates. Comparisons are done by the Regulations Advisor, who is looking to see if the costs are "reasonable" relative to past expenditures. Distribution companies have similar templates. However, distributors are being asked to separate out specific costs from the CAPEX template submission (known as "Building Blocks") including connections and disconnections, metering, meter installations, transformers, poles and wires, etc. These are identified as those specific jobs and materials that can be categorized discreetly and seen more or less as a commodity. These are the most likely to become the subject of benchmarking in the future. A sample of the filing requirements for Transmission and Distribution utilities is included in Appendix I.

Accountability has been recently transferred from state-based to a national regulator, and there are very clear instructions that this transfer is to be a smooth transition. Given changes in the regulatory framework, it is not likely that much progress will be made towards benchmarking over at least the next few years. Until the new regime is in place, it is not expected to take on developing new regulatory requirements and more comprehensive guidelines.

In Australia, climate change is seen as an issue that only impacts generators. Transmission and distribution companies focus on line losses, as they are transmitting the power generated over large distances. In general, transmission and distribution companies do not engage in greenhouse gas reporting, because they purchase power already generated and environmental impacts have been addressed elsewhere in the supply chain.

Australian regulators have identified that benchmarking is only useful if an organization's performance is benchmarked against true peers. In Australia, as with Canada, there are vastly different networks and operational environments, therefore regulators have suggested that the most effective benchmarking for revenue-setting is against an organization's own performance. In the views of the regulators, a well-designed incentive mechanism should allow companies to benchmark against themselves over time. Most recently the regulatory debate has focused on the use of the total productivity factor as a tool to help regulators assess the cost forecasts submitted through regulatory filings.

Utilities themselves, (generation, transmission and distribution companies) do a lot of their own benchmarking work. They participate in broad-based industry studies with multi-year trend analysis. This allows utilities to compare costs amongst themselves, looking out for like-for-like either locally or internationally. As with other jurisdictions, the key issue is finding a way to level the field of comparison. Since there is a confidentiality agreement between the consultant and the various participants, one only gets to hear about Utility A or B. However, being confidential means that different companies can review the performance scores themselves to see if it really applies to their business and make decisions accordingly.

New Zealand has limited use of performance metrics as the regulator has focused on creating a competition in those portions of the energy market which are not natural monopolies. Regulation is a recent phenomenon in energy policy, since competition law was initially seen as sufficient to control and define the industry. Emerging regulations deal only with aspects of the industry which are seen to require additional oversight.

4.2.3 FORMAL BENCHMARKING: THE U.K. EXPERIENCE

The Office of Gas and Electricity Markets (OFGEM) has been collecting information on utility performance and using formal benchmarking in the regulatory framework for a number of years.

OFGEM (formerly OFFER) has regulated network monopolies using a price-cap form of incentive regulation since 1991. Several market structure changes have occurred, the most significant of which was the introduction of NETA (New Electricity Trading Arrangements) in

2001 which replaced the centralized Electricity Pool. BETTA (British Electricity Transmission and Trading Arrangements) extends consistent rules across Britain including Scotland.

The electric industry structure in the U.K. is substantially different from Canada in that there is a national regulator (OFGEM), who works with the Department of Trade and Industry (DTI), the Government Department responsible for energy matters. There is only one transmission operator for the entire country, National Grid (NGC), who also acts as the system operator. Finally, there are 14 local distribution companies, known as Distribution Network Operators, or DNOs, which were established in 1991 at the time of privatization of the industry, and designed to be substantially homogeneous in size and demographics. This substantial similarity allows relative ranking of performance to be applied using a mechanistic formula that requires relatively less judgment on the part of the regulator. At present, the 14 DNOs are owned by 9 companies, as shown in Table 3 below.

Table 3: List of 14 UK Utilities and their Ownership

Company	Area
EDF Energy Networks	East England London South East England
Central Networks	East Midlands West Midlands
Scottish Power Energy Networks	Cheshire, Merseyside and North Wales South Scotland
CE Electric (NEDL)	North East England
Electricity North West	North West England
Scottish Hydro Electric Power Distribution	North Scotland
Southern Electric Power Distribution	Southern England
Western Power Distribution	South Wales South West England
CE Electric (YEDL)	Yorkshire

Price control reviews have been established at five-year intervals, and all the distribution companies are required to go through the reviews on the same basic timetable. While this creates a periodic burden for the regulator, it also enables a very standardized approach to these price reviews. Further, standardized reporting is imposed on the utilities, who report key statistics on an annual basis, so that the full reporting burden is spread across the five-year period, rather than concentrated only during the review year.

OFGEM is using benchmarking in the distribution price control reviews for the utilities. The standard set of performance metrics collected provides OFGEM with insight into utility performance and also creates a basis for cross-utility comparisons of productivity and performance. OFGEM also provides market surveillance oversight along with Energywatch (a U.K. publicly funded independent consumer/public advocate in gas and electricity issues). Like the regulators in Canada, OFGEM is responsible for monitoring the market and addressing consumer complaints. Compliance is an important part of the regulator's mandate and includes comprehensive monitoring, strict compliance and enforcement including use of coercion.

This compliance responsibility also includes the requirement of performing audits of large or small-scale portions of performance and reporting for the individual utilities. During the price control reviews, OFGEM undertakes a detailed review of the data submitted by each utility, prior to the actual price control review. These reviews often include a visit to the utility to discuss the filings and gain a more complete understanding of their contents.

The periodic price reviews provide an opportunity for the regulator to modify the reporting requirements for all the companies at once, at the same five-year intervals. The current set of metrics were used in the 2005 price reviews, and the new set, to be used for the 2010 price review period, will be published in February 2010. The 2010 price review is the 5th such review, and the level of reporting has increased in each one, leading to very detailed metrics being provided at this stage.

With respect to specific regulations, OFGEM imposes revenue caps on operations similar to regulated monopolies. The regulator has detailed output performance measures (i.e. on-time deliverable targets). Categories of performance for which the utilities are required to report results include the following:

<u>DISTRIBUTION</u>

- Distribution Costs – O&M and Capital
- IT Costs
- Taxation
- Staff Costs and FTE Numbers
- Materials
- Insurance

TRANSMISSION RELIABILITY

- System Performance (outages, unsupplied energy, availability/unavailability)
- Defects (by equipment type)
- Faults (by equipment type)
- Failures (by equipment type)

CUSTOMER SERVICE

- Payment Methods
- Debt
- Debt Repayment
- Prepayment Meters
- Disconnections for Debt

The above figures are reported quarterly and annually.

A more complete listing of the metrics, measures, and demographics is provided in Appendix D. They are listed in a document called Revenue Reporting Regulatory Instructions and Guidance (Revenue Reporting RIGs"), which provides comprehensive guidelines as to what to report, how to calculate various metrics, and then a series of forms for actually providing the data.

One interesting aspect of the U.K. example is the reliance on the strict review and audit process conducted under PAS 55 (the U.K. Asset Management methodology). This was a multi-sector initiative in Europe, backed by the British Standards Institute, designed to define what a full asset-management approach should include. It requires a life-cycle view and optimal mixture of capital investments, operations, maintenance, resourcing, risks, performance and sustainability. The electricity and gas distributors in the U.K. were required to implement the approach by 2008. Appendix J includes an excerpt from a document describing the entire array of topic areas covered in the specifications.

To reduce the amount of effort required and resources devoted to duplication of audit, those utilities which are certified under this methodology are exempt from comprehensive regulatory review.

4.3 BENCHMARKING FOR REGULATORY SUPPORT

With an overview of what is in place in other jurisdictions, it is important to take consider what regulators in Canada can do with this information, both immediately and in the future. This is augmented by how utilities are currently using benchmarking and what they are providing to regulators to support their rate filings.

4.3.1 WHAT CAMPUT CAN LEARN FROM THESE EXPERIENCES

In addressing whether and how CAMPUT members could effectively adopt these practices for purposes of comparison, each of the jurisdictions cited offers some learning.

The U.S. experience has provided a comprehensive inventory of information (bank of data) to be collected, compared and mined for overall observations of the industry. However, due to the fragmented nature of regulation, little has been done in the way of analysis and application of the learning, at least as far as cross-jurisdictional benchmarking to support regulation.

The Australian experience, with a push to national regulation, addresses this concern of fragmented local policies, but is in the early stages of restructuring. This market is worth watching, if and when they begin to consider an approach to benchmarking at the national level. Both provide some insight into possible directions to be taken, but provide little in the way of formal and immediate recommendations for benchmarking that can be adapted for Canada.

By contrast, the OFGEM experience provides a mechanistic framework that includes a comprehensive inventory of information (in the form of performance metrics) that provides clear insight into utility performance, and addresses issues of compliance, audit and information risk in a way that can be transferred to other jurisdictions including Canada. However, when applying their approach to ratemaking, the nature and complexity of Canada's utilities industry and our regulators requires an evolutionary approach with a clear understanding of the impact of the demographic differences.

Before metrics can be used in ratemaking, it is prudent to understand the value of the information being collected. This will involve probing to determine if the data are in fact comparable, not only based on definitions provided but in how these definitions are implemented in the data collection process. It will also require established data collection for a number of cycles, to identify acceptable ranges in performance. This should include ensuring that a process is in place to address the demographic characteristics and differences in the individual utilities and the jurisdictions in which they operate. All these differences must be appropriately identified and addressed in any formal cross-jurisdictional comparisons.

4.3.2 WHAT IS ALREADY IN PLACE ACROSS CANADA

Many utilities have begun using benchmarks in support of rates and regulatory proceedings. Sometimes these utilities choose to do so, and sometimes the regulators require it. The reasons and the approaches vary by jurisdiction and by utility. Some of these studies are done in-house by the utilities, while others are done by engaging consultants to perform the studies, and prepare written and verbal testimony in support of the filings. A few examples can help in illuminating the types of uses.

In recent years, Hydro One has commissioned significant studies in support of both their transmission and their distribution rate cases. Their approach in those situations has been to provide data showing how they compare in terms of both reliability and cost versus other similar-sized utilities. Because of their unique size, service territory demographics, and system design, they have found it necessary to go outside the province of Ontario to find appropriately comparable utilities for comparison. The benchmarking work has been a small but significant part of their filings, as well as the discussions during those filings.

The benchmarking study used by Hydro One in their 2008 distribution rate case covered several subjects in its scope in order to provide a balanced view of company performance, and the resulting report was helpful both to the company and to the regulator in determining an appropriate rate outcome. The key findings of the study included the areas of:

- Cost
- Asset Replacement Rate
- Reliability
- Safety
- Meter Reading
- Tree Trimming

Having been filed as part of the rates proceeding, the benchmarking report is a public document. A copy of the executive summary from the Hydro One benchmarking report is provided as Appendix K to this report.

B.C. Hydro has used the results of large-scale benchmark studies in their rate proceedings in the past ten years. They have chosen specific types of information to demonstrate specific points about their capital investment levels as well as highlighting their O&M approach. For them, the benchmarks are a support tool, rather than a primary tool for making their case.

Direct Energy, an electric and gas retailer, has recently engaged in two separate benchmark studies in support of rates proceedings regarding their services in Alberta. These studies are in support of customer service for their gas and electric customer base. One was encouraged by the Alberta regulator, and one was done of their own accord. The first was commissioned as a collaborative study, with input from intervenors, regulatory staff, and their own staff, with a consultant hired to perform the actual study. The idea behind that was to get a study that would be understood and supported by all sides. The second was commissioned directly by Direct Energy, and done at their direction by a consultant. The first study has taken over two years, and is still in development, with disagreements among the various stakeholders about the terms of reference for the study. The second did not require the agreement of a number of stakeholders, and was completed in about six months from start to finish. This experience points out some of the difficulties associated with running a study that will need to be accepted by a wide array of stakeholders.

The two studies commissioned by Direct Energy were focused on the customer care activities of the company, including call center operations, billing and payment processing, and credit and collections. In each case, a peer panel of companies across North America was targeted, in order to be able to assess market prices for each of the three major areas of service, for comparison against the costs incurred by Direct Energy in providing the services.

There are other examples where benchmarking is performed for regulatory purposes. The OEB used Reporting and Record Keeping Requirements (RRR) data in its regulatory processes to support and test the reasonableness of an applicant's proposed OPEX, CAPEX and reliability performance in the context of a cost of service review. The OEB has collected RRR cost data on Ontario's electricity distributors and used this data to group them for the purpose of staggering distributor rate rebasing reviews over a period of four years.

The OEB uses benchmarking to determine annually an electricity distributor's stretch factor under its 3rd generation incentive regulation plan. Different stretch factors are applied to different companies; the sector is divided into three different efficiency cohorts based on OM&A benchmarking studies, with lower stretch factors for more efficient firms. Efficiency is determined using two benchmarking models developed by Pacific Economics Group which produce an approximate “bell curve” distribution of efficiency rankings. The approach tailors the X factor to reflect differences in productivity and efficiency, while providing a foundation for more comprehensive (i.e. total cost) benchmarking in the future. Each year the cohorts for the entire sector are re-evaluated. This approach recognizes and rewards distributors for efficiency improvements during the term of the incentive regulation plan.

In our exploration of jurisdictions both national and international, we have seen that many regulators have reporting requirements wherein the utilities are required to report various statistics, including costs, service levels, and operating statistics. This is a rudimentary form of benchmarking in that the outcomes are compared, but there is very little in the way of use of the results to make performance improvements by the utilities. The companies submit the reports, and there are penalties, along with occasional rewards, for extreme outcomes. The companies tend to make changes necessary to meet the penalty criteria, but usually on a secondary basis, rather than using the regulatory targets as the primary drivers of how they run their businesses.

5 PROPOSED PERFORMANCE INDICATORS AND BENCHMARK MEASURES

In this section, we outline the performance metrics we believe would be most useful and practical for use in benchmarking utility performance by regulators. The proposed metrics are designed to provide an overview of the information required by regulators to understand the performance of the utilities. We have relied on an inventory of the data that are available, our discussions with both regulators and utilities on how the data could and should be used, and our long history of performing benchmark studies. Those experiences have given us a clear perspective on what is both desirable and possible in performing benchmark comparisons. Combined with our extensive understanding of the regulatory environment in Canada, we present what is achievable in the near term and a path to expanding in the future.

The discussion also includes the demographic variables to be tracked and an explanation of the value of existing standards for reliability and safety.

5.1 SELECTION CRITERIA

As established in Section 3, the purpose and use of benchmarking by a regulator is different from that of a utility. This report attempts to balance the needs of the regulator with the concerns of the utilities, to create a set of metrics that can be implemented effectively to establish the basis for benchmarking across jurisdictions in Canada.

From a regulator's perspective, the selection criteria should include:

- Facilitating, protecting and serving public interests
- Making regulatory processes more efficient and effective
- Helping balance consumer interests and financial interests of utilities
- Supporting ease of tracking and reporting by presenting metrics that can be easily understood, objective and transparent

Any metrics proposed should clearly identify how they can be used to facilitate cross-jurisdictional benchmarking among CAMPUT members.

Several other criteria were used in developing the list of proposed performance indicators below. It was necessary to have the criteria in place prior to selecting the metrics, to assure that the resulting set fit together cohesively and comprehensively. The selection criteria included the following:

- The selected set of metrics should be balanced, covering both service levels and costs
- A manageable, limited set, focused on outcomes, rather than underlying process results
- Metrics should be measureable by each utility, and should help them in running their business (i.e. they should be tracked and used internally, as well as for regulatory reporting)
- Results should be understandable to everyone, (in other words, not a "black box" model creating an index that is unexplainable to the average observer).
- Appropriate demographics should be included in the data collection to enable the users to recognize and account for differences among utilities in their operating circumstances.

A more comprehensive set of benchmark metrics is presented in Appendix A, as part of the glossary. The metrics on that list are ones that most utilities would reasonably be expected to track for their own use in managing their business, and in helping them to understand the higher level results represented by the proposed regulatory benchmarks.

5.2 Focusing on a Short List of Specific Metrics

As long as the metrics proposed are limited to a few relevant key areas, it is easy to see how meaningful data can be made available. A few areas of concern for both regulators and utilities are:

- **Customer care** allows regulators to understand how a utility is delivering on the promise it is making to customers and meeting the objective of utility accountability.
- **Asset management** addresses the balance between investing in new infrastructure and establishing a robust maintenance program, to avoid interruptions in service or unexpected repair costs.
- **Operations** focuses on the efficient delivery of electricity and timely installation of new connections; it goes to the reliability of the system and the way it is managed.

- **Costs** to ensure that there is a prudent use of resources to ensure reasonable rates, but that enough is invested in the organization to ensure continued delivery of quality service.

Keeping these four areas in mind, we considered how both a regulator and the utility would apply benchmarking in these areas. The tables below identify the benefit to CAMPUT members in tracking each of the metrics, and how they meet regulators' objectives. They are at a high level, representing key performance outcomes in selected categories outlined below.

5.3 PROPOSED METRICS

A short list of metrics has been identified for consideration by CAMPUT. They are grouped into the following categories

- Customer Service
- Transmission
- Distribution
- Costs
- Other (Optional)

These groupings were selected to reflect the major functional areas in electricity transmission and distribution utilities in Canada. By focusing on these items initially, regulators will be able to create an overview of performance in key areas, and begin the process of compiling standards for operational effectiveness. The information will also provide sufficient detail to diagnose the overall health of the utilities under review, while remaining at a high enough level of aggregation to ensure sufficient comparisons are possible.

5.3.1 CUSTOMER SERVICE METRICS

The metrics shown in Table 4 on the next page reflect the key functions in customer care, call centre, billing and complaints. Service level and billing accuracy are common KPIs and can easily be compared across utilities regardless of size and other differences. The final metric in this grouping, customer complaints, is equally important but will differ across utilities and jurisdictions. The volume of customer complaints is affected by a variety of factors which may not always be within the control of the utility, but this can be addressed through further investigation of values which are outside the accepted range.

Table 4: Customer Service Metrics

Metric	Description	Calculation	Criteria Met	Primary and Secondary Applications for CAMPUT Members
Call Centre Service Level	Percent of calls answered in 30 seconds, including abandoned calls. Calls are counted after they have left the IVR.	Calls answered within 30 seconds/(calls answered + calls abandoned)	Balanced, manageable, measureable, understandable, accommodate demographics	**Primary: Compliance** **Secondary: Audit** This metric is easily compared across different types of organizations. A standard metric for outsourced contracts, this can be used as a simple proxy of the level of customer service provided by the utility.
Billing Accuracy	Errors found on the bill after the bill is delivered to the customer. Errors are anything that needs to be corrected. Exceptions include planned manual adjustments, adjustments at the request of the customer and not a result of an error (e.g. waiving fees).	# of bills corrected and reissued / # of bills issued.	Balanced, manageable, measureable, understandable, accommodate demographics	**Primary: Compliance** **Secondary: Audit** This metric is easily compared across different types of organizations. This is useful in explaining how effective the utility is in sending out invoices which will in turn result in revenue collection.
Customer Complaints	Annual number of complaints filed with the regulator, normalized per 1000 customers.	# of customer complaints / (# of customers/1000)	Balanced, manageable, measureable, understandable, accommodate demographics	**Primary: Compliance** **Secondary: Ratemaking** This metric is easy to collect, but will require some interpretation, since not all complaints filed are valid. Used by many regulators, this is intended to represent how effectively the utility is meeting its regulatory requirements.

The metrics listed in Table 4 above are collected and reported in many jurisdictions, especially in cases where a set of cost metrics have been put into place. They represent a very minimal set of measures for the level of customer service. Of the three, the billing error rate is least often found in use.

5.3.2 TRANSMISSION

These metrics focus on asset management and the importance of capital expenditures. The replacement rate metric includes CAPEX, except for new business. For transmission utilities, the normalization based on total assets is reasonable because assets is a better predictor of costs than is the number of customers. For transmission, the number of customers served is not relevant as a normalizing factor, since the system is created to deliver bulk energy, not to serve customers. Measuring transmission on a per customer basis would be similar to measuring generating plants on a per customer basis.

In the way they are defined in Table 5 below, the transmission asset replacement metrics have not yet found wide use in other regulatory jurisdictions. In most cases, what is found is a one-year figure for capital spending, or, in the case of the U.K., a review of the entire five-year price review period is used. Also, the majority of the metrics in use are focused on total capital spending, rather than on the “maintenance capital” or “replacement capital” as identified here.

Table 5: Transmission Metrics

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
3-year Average T&D Substation Replacement Rate	The 3-year average of total capital investment less spending on connection of new customers or additions of new stations to feed new load divided by total substation assets	{[(current year substation capital spending-current year capital additions for new load)/current year asset base at end of year] + [(last year substation capital spending-last year capital additions for new load)/last year asset base at end of year]+ [(2 year's ago substation capital spending-2 year's ago capital additions for new load)/2 year's ago asset base at end of year]}/3	Balanced, manageable, measureable, understandable, accommodates demographics	**Primary: Ratemaking** **Secondary: Audit** To provide additional insight to the Asset Management strategy of the utility; will be affected by size of the system and age of the infrastructure.

Table 5: Transmission Metrics (cont'd)

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
3-year Average Transmission Asset Replacement Rate	The 3-year average of total capital investment less spending on new lines divided by total transmission assets	{[(current year T-lines capital spending- current year capital additions for new lines)/current year asset base at end of year] + [(last year T-lines capital spending- last year capital additions for new lines)/last year asset base at end of year]+ [(2 year's ago T-lines capital spending-2 year's ago capital additions for new lines)/2 year's ago asset base at end of year]}/3	Balanced, manageable, measureable, understandable, accommodates demographics	**Primary: Ratemaking** **Secondary: Audit** To provide additional insight to the Asset Management strategy of the utility; will be affected by size of the system and age of the infrastructure.

5.3.3 Distribution Metrics

This section focuses on the importance of reliability in distribution systems. For distribution, the reliability measures SAIDI, SAIFI, and CAIDI should exclude loss of supply as the distribution company does not have control of loss of supply on a transmission system. SAIDI is included as the final measure of reliability as per the information provided in most regulatory filings, even though CAIDI is the ratio of SAIDI to SAIFI. Again, CAPEX is captured through the information on replacement rates. For distribution lines, the number of customers is equally good at predicting total costs as is the total asset value. We have recommended using this metric, but using total customers as a normalizer for distribution is equally useful.

Recommended metrics appear in Table 6 on the next page.

Table 6: Distribution Metrics

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
3-year Average Distribution Asset Replacement Rate	Average % of the existing distribution lines which are replaced annually, calculated on the basis of a 3-year average. Capital spending for addition of new customers is to be removed from the calculation.	{[(current year D-lines capital spending-current year capital additions for new customers)/current year asset base at end of year] + [(last year D-lines capital spending-last year capital additions for new customers)/last year asset base at end of year]+ [(2 year's ago D-lines capital spending-2 year's ago capital additions for new customers)/2 year's ago asset base at end of year]}/3	Balanced, manageable, measureable, understandable, accommodates demographics	**Primary: Ratemaking** **Secondary: Audit** To provide additional insight to the Asset Management strategy of the utility; will be affected by size of the system and age of the infrastructure.
SAIFI (excluding major events, planned interruptions and loss of supply)	Average number of interruptions experienced by the average customer during a year. Exclude major events and planned interruptions/loss of supply from the numerator.	Sum of all customer interruptions / total number of customers served (excluding interruptions caused by major events and planned interruptions)	Balanced, manageable, measureable, understandable	**Primary: Ratemaking** **Secondary: Audit** To ensure reliable system performance
CAIDI (excluding major events, planned interruptions and loss of supply)	Average length of an interruption before restoration of service. Exclude major events and planned interruptions/loss of supply from the numerator	Sum of all customer interruption durations / total number of customer interruptions (excluding interruptions caused by major events and planned interruptions)	Balanced, manageable, measureable, understandable	**Primary: Ratemaking** **Secondary: Audit** To ensure reliable system performance
SAIDI (excluding major events, planned interruptions and loss of supply)	Average number of minutes of interruption experienced by the average customer during a year. Exclude major events and planned interruptions/loss of supply from the numerator.	Sum of all customer interruption durations / total number of customers served (excluding interruptions caused by major events and planned interruptions)	Balanced, manageable, measureable, understandable	**Primary: Ratemaking** **Secondary: Audit** To ensure reliable system performance

The reliability metrics suggested above are more or less standard across the regulatory jurisdictions in the world. "More or less" standard means every jurisdiction using benchmarks uses a form of these metrics, although the definitions of what is to be excluded vary from jurisdiction to jurisdiction. In some cases, the names for the metrics vary from SAIDI/SAIFI/CAIDI, but underneath the name, the calculations are equivalent.

5.3.4 OPERATIONAL OR COST METRICS

With the exception of transmission and substation costs, all cost measures identified are normalized based on number of accounts (or customers). For customer service costs, this is clearly the best normalizing factor to use, since most of the costs are driven by the number of customers and the services provided to them. For distribution costs, the number of customers is a very accurate predictor of average costs, in large measure because beyond a minimal threshold there are very few economies of scale in distribution. However, some judgment must be exercised in using customers to normalize distribution costs. In particular, electric systems with extremely high or extremely low customer density typically don't fit the cost model on a per-customer basis. In those cases, a better normalizing factor is the asset base. Given this circumstance, in the case of distribution OM&A, it is reasonable to track both cost per customer and cost per asset, in order to appropriately address the situation of utilities with extreme (high or low) density levels, as well as ones with atypical percentages of large customers.

Although compensation was mentioned by some regulators, it is captured within Administration and General (A&G) costs, as a part of doing business. By capturing A&G costs separately, regulators will be able to understand the impact of the bundle of compensation-related expenses.

The cost metrics noted in Table 7 on the following pages are in use in many jurisdictions in one form or another. In the case of the customer service metrics, most regulators, when reviewing the customer service functions, compare total costs against customers. The mildly unique feature of the metrics suggested is the focus on write-offs, which are certainly measured by utilities everywhere.

Table 7: Cost Metrics

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Customer Care				
Cost Per Account	Total cost of providing customer care services per customer	Sum of costs for customer care functions (contact center, billing & payment processing, meter reading, field service, credit, customer service IT) divided by total number of customer accounts.	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This metric reflects the cost of customer care on a per customer basis (operational efficiency). Although a relatively common measure of efficiency, utilities with a very small customer base may be at a disadvantage because they do not achieve economies of scale.
Cost per Account (excluding write-offs)	Total costs of providing customer care services, excluding write-off costs	Same as above, excluding write-off amount.	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** As above; also able to capture the impact of bad debt. Write-offs are the single largest cost category in customer service, and they are affected substantially by economic factors outside the control of the utility. Tracking total costs without this large element helps in understanding the controllable operating costs.

Table 7: Cost Metrics (Cont'd)

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Customer Care				
Write-offs as a % of revenue	Write-off amount divided by total revenues is intended to capture bad debt.	$ of customer bills written off/ total customer revenues	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** Used for **Audit** - this metric reflects how effectively the utility is managing collections and addressing bad debt, as well as helping identify the impact of regulatory restrictions on collections actions

Table 7: Cost Metrics (Cont'd)

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Transmission				
T&D Substation O&M per T&D Substation Asset	Substation O&M spending per asset. Designed to monitor the ongoing operating costs, normalized by the size of the asset base.	Costs associated with operations and maintenance of all substation equipment / total substation assets.	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This metric reflects expenditure on substation maintenance and operations, may identify that insufficient funds are being applied to upkeep which could result in outages or costly emergency repairs
Transmission Line O&M per Total Transmission Assets	Transmission Line O&M spending per asset. Tracks the ongoing operating costs, normalized by the size of the asset base.	Costs associated with operations and maintenance of transmission line equipment per total transmission assets.	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This metric reflects expenditure on transmission line maintenance and operations, may identify that insufficient funds are being applied to upkeep which could result in outages or costly emergency repairs

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Distribution				
Distribution O&M Cost per total (gross) distribution assets	Operating and maintenance spending per total distribution assets. Tracks the ongoing operating costs, normalized by the size of the asset base.	Distribution operating and maintenance costs / total distribution assets.	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This metric reflects expenditure on distribution system maintenance and operations, may identify that insufficient funds are being applied to upkeep which could result in outages or costly emergency repairs
Distribution O&M Cost per customer	Ongoing costs of distribution operations, normalized by the number of customers those costs are spread across.	Operating and maintenance costs / # of customers	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This reflects expenditure on distribution system maintenance and operations. Extreme values can highlight either under-spending or over-spending on the system.
Corporate Services				
Administrative and General (A&G) costs per Account (customer)	Sum of corporate overhead costs divided by the number of customers who those costs are ultimately borne by.	Legal,HR, accounting, corporate and shared services costs / # of customers	Manageable, measureable, understandable accommodate demographics	**Primary: Ratemaking** **Secondary: Audit** This metric identifies if pensions and benefits or other overhead costs are an area to be explored.

It may be noted that for the transmission metrics, the use of the asset base as the normalizer of choice is one that many U.S. states use for their comparisons. OFGEM uses a variety of metrics in the U.K., including these. It isn't "benchmarking" there, because there is only one provider, so the comparisons are against the National Grid history, rather than against other providers in the country.

Distribution and A&G metrics are tracked on a per customer basis in most jurisdictions, while the distribution per asset metrics are less frequently used. Many U.S. states use the per-asset metric in addition to the per-customer metrics.

5.3.5 Other (Optional) Metrics for Consideration

This final set of metrics is included for consideration based on their relevance for understanding the overall economics of the business or because they have been mentioned as important by a number of regulators during the research phase of the study.

Many of these metrics will be difficult to track across all jurisdictions (line losses, new services) because although definitions may be similar, starting points for assumptions will differ. For example, identifying when the time clock begins for a new service and agreeing what criteria meet the customers' expectations. There are also some, like conservation, which will not be relevant to all. However, as the importance of environment and conservation begins to increase, it will be valuable for CAMPUT to have a baseline for this metric. In the case of public safety, there are a number of potential indicators, none of which is universally standard across the industry.

Table 8: Other Optional Metrics

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Public Safety	Number of public safety incidents incurred by each utility annually. Could be categorized by incident type (e.g. electrical contact, hit pole, etc.). Will need to be normalized by exposure levels, e.g. km of line in service.	Number of public safety incidents incurred by each utility annually / km of overhead lines.	Balanced, manageable, measureable, understandable accommodate demographics	**Primary: Compliance** To help in understanding the impact of electric systems on the public.
Line Losses	Losses of energy through the distribution network as a % of energy into the system.	Sum of energy introduced into the distribution network through trans-mission network and distributed generation, less the amount delivered (metered and unmetered) at the customer meters, divided by the amount entering the distribution network	Balanced, manageable, measureable, understandable accommodate demographics	**Primary: Compliance** **Secondary: Audit** To address environmental impact associated with electricity transmission and distribution; this metric is not always easily measured so it is best to begin with capturing for only those who are able to provide. Some judgment will be required in interpreting values.
New Services	Percentage of requests for new services executed within the dates agreed with customer or within the timeframe established by policy. New services include new connections to the grid, or upgrades. Calculated as number of requests executed within established timeframe/number of requests.	# new services completed by agreed dates / number of new services installed.	Balanced, manageable, measureable, understandable accommodate demographics	**Primary: Compliance** **Secondary: Ratemaking** To address the operational effective-ness of the organization, and ability to meet customer expectations.

Table 8: Other Optional Metrics (Cont'd)

Metric	Description	Calculation	Criteria Met	Application for CAMPUT Members
Conservation per Customer	Measuring the amount of conservation undertaken by those utilities which practice it.	kWh savings as a result of utility delivered conservation divided by the number of customers	Balanced	**Primary: Ratemaking** **Secondary: Compliance & Audit** A measure to address environmental impact; will not be relevant to all jurisdictions, but an important indicator to begin tracking in those areas where some activity is underway.

5.4 EXPLAINING THE CHOICE OF METRICS

All the metrics included in this section would be tracked, where applicable, for information purposes only. Once a range of relevant values is established, the requirement to report can be modified. The value and relevance of these metrics should be reconsidered for the 2-5 year timeframe.

Regulators might be tempted to ask why is it important for an economic regulator to consider employee safety while there are other government entities (such as Workers Compensation Board as well as Ministry of Labour) that are mandated to provide oversight on both employee and public safety? The issue is similar to tracking electric system reliability, or customer service levels. Those are not strictly economic considerations either. It is part of responsible management of the utility to assure a safe workplace, and a responsible regulator should look at the broad performance of the company from several aspects in order to recognize superior (or substandard) performance. An appropriate way for CAMPUT members to use safety metrics would be as a "minimum" level of performance – i.e. meeting a certain minimum performance level then enables rates decisions to ignore the safety results. Failure to meet the minimum requirements could result in some form of penalties. Most utilities would not be affected but it would allow the regulators to feel confidence in the all-around performance of the utility.

5.5 DEMOGRAPHIC VARIABLES TO TRACK

Demographic variables are important to track for two key reasons. First, they provide a mechanism for normalizing many of the performance factors (e.g. costs), which enables comparisons of companies that aren't identical. For example, comparing a very large company on the basis of total costs against a very small company makes no sense until the costs are normalized to take out the direct effect of the size difference. The second reason demographic variables are important is to enable understanding of the factors that affect performance, and which are generally not controllable by the companies.

By definition, demographic variables are characteristics about the companies which are not changeable in the short term, and which are likely to affect performance outcomes in some significant way. For example, the % of the distribution system that is overhead will have an impact on both costs of operations and on electric system reliability due to the exposure to weather and other hazards created by the configuration. It is not something the utility can change in a year or two, and it affects many aspects of performance results. Comparing companies while understanding the influence of the demographic variables provides both companies and regulators with a means of making fairer comparisons and more accurate assessments of the performance of the utility.

Initially, we are recommending a small number of demographic variables to be tracked and reported to the regulatory bodies. At a minimum, the following demographics should be tracked:

- Number of customers
- Asset value for distribution, transmission, and substations
- Customer density (per square km and per km of line)
- Percent of the distribution system overhead versus underground

Those variables are necessary for normalizing factors, and for understanding the expected costs of operations and maintenance of the electric system. In Appendix B, a larger number of demographic variables are listed, with specific elements tied to customer care activities as well as distribution. The table in Appendix B provides a number of demographic variables that should be tracked by the companies for their use in understanding their relative performance, and as the benchmark process becomes more familiar to utilities and regulators, some of those should be moved into the grouping that is reported on a regular basis. Each of the 4 variables above is briefly discussed here.

Number of Customers – this is the primary normalizing variable for customer service costs. Simply stated, each customer can be expected to create a certain amount of costs to serve, from calling the call center to paying bills to occasionally being late on payments. It is also one of the better normalizing factors for distribution costs, although not quite as good as the value of the assets.

Asset Value – This is also a normalizing factor for use in comparing the costs of different companies. The asset value is a surrogate for the size and complexity of the electric system, and as such serves as a measure of what drives operations, maintenance, and capital replacement.

Customer Density – this is an explanatory variable. By itself, it doesn't explain the overall costs of operations, but helps to explain differences among companies with similar numbers of customers and asset bases. It is particularly useful in explaining costs for functions where travel is involved (e.g. meter reading, field service, distribution operations and maintenance), and it has no bearing at all on office-based activities such as call center operations or billing.

% Overhead versus Underground – This is an explanatory variable which helps in understanding both costs and reliability. The exposure to weather and other hazards for overhead lines leads to poorer reliability, and at the same time higher routine maintenance costs. On the other hand, capital installation costs are lower for overhead lines, so there is a tradeoff.

Many other demographic variables have an impact on performance of individual functions of the utility. For example, the propensity for customers to call the utility in a given region or area can be much greater than in other areas, and will lead to higher costs of operating the call center. It won't have any impact on the costs of vegetation management, or many other areas of distribution. Understanding the demographics which drive performance in all areas of the utility will help in the analysis of performance. Eventually, it will be beneficial to add to the number of demographic variables to track and analyze, but for now, CAMPUT members should begin with a very limited selection of such variables to work with.

5.6 EXISTING STANDARDS

Before leaving the discussion of metrics, it is important to consider how they might be used and applied. To help understand the proposed metrics, it is reasonable to consider how similar metrics are used today to establish standards for performance.

There are a variety of “standards” in place across the industry for various components of the business. Some of these have been created by government and regulatory bodies, while others have been developed by voluntary groups and industry associations. Most of these “standards” do not require compliance from all utilities, so they can more fairly be considered as “guidelines” than “rules” that utilities must follow. This section is structured to review standards for customer service and reliability (two of the areas highlighted in the proposed metrics). Additional details on other types of standards are included in Appendix G.

5.6.1 CUSTOMER SERVICE STANDARDS

Standards of customer service tend to fall into two categories: objective service levels as measured by specified metrics, and customer complaints as measured either by complaints to a regulator, or complaints directly to the utility.

Customer complaints are important to both the utilities and the regulators. They are the most direct method for identifying areas where customer expectations are not being met. The definition of a “complaint”, however, isn’t consistent from jurisdiction to jurisdiction or from utility to utility. In some jurisdictions, to achieve “complaint” status, a customer inquiry must go through several steps of escalation from the initial contact, typically with the contact center, through various levels of management in the utility, and then on to very formal steps in being registered by the regulator as a complaint. In others, a complaint can be registered simply by calling or writing to the regulator, and then the process works backwards to the utility to understand and resolve it.

Whatever the mechanism, in most circumstances, the definition of a complaint is clear between each utility and its regulator, and there are often targets as to how many are acceptable in a year, and what response time is reasonable. To call them “standard” definitions is a stretch, since they are very different from one jurisdiction to another. What is consistent is that almost all utilities are required to track and report complaints and the timeliness and outcomes of the responses. More on customer service including customer satisfaction standards can be found in Appendix G.

5.6.2 Reliability Standards

There are a number of ways in which standards have been set for electric system reliability. Most recently, NERC has issued new rules for reporting and behavior that affect the utilities. These are primarily focused on transmission, and include both metrics and reporting approaches.

In the past two years, another set of transmission reliability standards have been developed and are in the process of being implemented. These are called the "TADS" measures (Transmission Availability Data System) and they are designed to address transmission reliability more from a circuit component standpoint than from an end-use customer perspective. They recognize that traditional customer-focused measures of reliability don't very effectively track success in transmission. The TADS metrics were developed through a voluntary industry effort in which individual utilities had representatives on a committee who worked to create them. Although 2009 was the first year in which most large companies are reporting the TADS metrics, and while it is experimental, it appears as though they are going to be successful. There are likely to be minor modifications to them over the next few years, but the basics are in place now.

In the distribution reliability arena, there are a number of generally-accepted metrics in use for tracking reliability performance, and while they are generally understood, the actual mechanics of measuring those metrics have varied among North American utilities. In this area the most well-known metrics are SAIDI, SAIFI, CAIDI, and to a lesser extent, MAIFI. The theoretical formula for measuring each of these is known, and is essentially the same for everyone, but the ability to capture the data varies from utility to utility. For example, in tracking outages, some companies are able to isolate outages to each individual customer location, and track precisely when each location is restored to service. In other cases, the distribution system is only able to identify specific devices (fuses, switches, etc.) that failed, and thus must approximate the number of customers who were out of service during an incident. The net result is that two utilities experiencing exactly the same outage situation might report a different number of customer minutes of outage (SAIDI). With increasing sophistication of both electric grids and outage management systems, companies have improved on their ability to measure more precisely, so today the differences between companies are smaller than they once were, but they still certainly exist.

A more important difference (i.e. lack of standardization) among utilities is what outages they exclude from their reporting of outage statistics. It is desirable to report the "controllable" outages, i.e. those not created by major storms or similar unexpected events. The issue here is how to define an extraordinary event. There is no universally-accepted standard for how to define these major events, and therefore the performance statistics for SAIDI, SAIFI, CAIDI excluding these events are inconsistent. In the past five years, the IEEE has worked through a collaborative process, once again with volunteers from individual utilities, to develop a means of defining extraordinary events. The result is known as the "2.5 Beta" method, built largely around statistical analysis of the number of customers out of power during each event. In the most recent 1QC benchmark study of North American utilities, just under half of the utilities were found to have adopted this method for use in tracking reliability statistics. However, there are a number of utilities who have indicated their disagreement with this approach, and they have stated they will not be adopting it. So this IEEE "standard" is not really a standard as of yet.

Various states and provinces have applied different standards for reliability, both between jurisdictions and between individual utilities within jurisdictions. For example, in the state of New York, companies are required to report their reliability as measured by SAIFI and CAIDI, but the required performance levels ("standards?") are different for each company, based primarily on their past performance, along with some recognition of the differences in service territory demographics and system designs. Other jurisdictions have similar situations – they have chosen specific metrics, and (usually) the same measurement and exclusion approaches, but with different targets for different utilities. And, of course, many utilities have no set targets at all.

Another major area of interest for utilities with respect to electric system performance is that of power quality. This is essentially the elements of power delivery that don't include sustained outages, but which do influence the power actually delivered. It is typically measured as "momentary" outages, which in some cases range up to five minutes in length, and in terms of voltage variations and frequency variations. The American National Standards Institute (ANSI) provides the most universally accepted definitions, with descriptions of recommended voltage ranges for typically-used system voltages and configurations. Actual acceptable variation levels, as with reliability levels, vary from jurisdiction to jurisdiction, so as with reliability, there are accepted metrics, but not universally used targets for performance, even within jurisdictions.

5.6.3 SAFETY STANDARDS

Employee safety, in an industry with the potential dangers of electric power, is naturally a very important subject to the utilities, arguably the most important one. All utilities track their safety records, using generally-accepted metrics and definitions. Safety metrics fall into two major classes – those measuring frequency of safety incidents, and those measuring severity of incidents. The key metrics used in tracking frequency of incidents in Canada are called the All Injury/Illness Frequency and the Lost-Time Injury/Illness Frequency. The Lost-Time Injury Severity Rate is used to track the seriousness of the injuries.

In the U.S., safety standards are set by the Occupational Safety and Health Administration (OSHA). There, companies track "recordable incidents", which indicate the frequency of accidents, regardless of severity. "Lost-Time incidents" identify those incidents which result in some amount of lost work time due to the incidents. Finally, "Severity Rate" measures the average amount of time off work created by incidents. The measures used in the U.S. and Canada are very similar, and allow comparisons of results between utilities in the two countries.

6 CHALLENGES WITH BENCHMARKING AND REPORTING

There are a number of significant challenges to the goal of developing a standardized benchmark set for comparing utilities across Canada, as well as within individual Provinces and Territories. Some of those challenges (e.g. demographic differences) can be dealt with through the use of appropriate normalizers, peer panel selection, and good choices of performance metrics. Others will be more difficult, as information collected and the data collection process is cumbersome in the regulated environment. There are also both deliberate and benign reasons the utilities will have trouble measuring and reporting appropriate metrics. By recommending a short list of easily available metrics, the task of data collection will not derail the launch of a more comprehensive set of benchmarking initiatives. It will also introduce a framework for discussion and debate, early in the process to ensure that stakeholders are engaged and given the opportunity to evolve the mechanism for creating standards for electricity transmission and distribution utilities in Canada.

This section defines challenges from the perspective of both regulators and participants and the operational or implementation challenges that will need to be overcome.

6.1 REGULATOR PERSPECTIVES

6.1.1 REGULATORS' CONCERNS IN USING BENCHMARKING

For those regulators who identified that performance metrics were not currently in use, there were a number of barriers identified when considering the use of benchmarking. Regulators identified a variety of reasons as rationale to support why benchmarking is not a valuable practice. Most dealt with the amount of data and value for comparison.

Many regulators identified that little benchmarking was conducted because the utility or utilities they regulated were unique and did not have valid comparators. The 'apples to apples' comparison was presented in a number of jurisdictions as geographic or demographic barriers existed that would prohibit clear comparisons. This might be reflected in a single Crown Corporation that provided generation, transmission and distribution services to a broad geographic area or a small local utility that sourced all of its generation from another province. A number of non-traditional LDC models exist in Canada due to the size of the country, population density and distribution and the origins of the utilities. Most utilities were able to provide some level of in-kind comparators, but were unable to define what they perceived to be a valid comparator group. The geography and population distribution across Canada limited local options for Peer Groups for comparisons. For those willing to look outside to the United States, similar concerns were raised, with the additional impact of local regulatory and government intervention. Although this may be a valid concern for taking action based solely on the results a benchmarking study, it does not limit the value as a data collection exercise.

Availability of data was also raised as a general concern. Regulators identified that many of the utilities they regulate have suggested that the type of information requested is either not available or not in the format required. The incremental work associated with collecting the data and providing it in the required format would be significant. Again, given that valid comparators were not obvious, there seemed little value in suggesting standardized reporting on a set of specific metrics. Although regulators did identify that clearly defining simple metrics and providing a wide range of values for comparison might ease this concern. It may be true that a comprehensive data collection exercise similar to those undertaken in the U.S. and U.K. may not be a suitable starting point; it is not a sufficiently strong concern to rule out establishing a shorter set of simple metrics to launch the data collection process and begin building a national data inventory.

Finally, past objections had been raised about the clarity of the requirements, definitions of the metrics and an insufficient understanding of how it would be used. Those jurisdictions that do not currently use benchmarking identified that the utilities they regulate were concerned that comparisons without clarifying consideration would position them unfavourably and misrepresent both the efficiency and effectiveness of their operations.

The 'Crown Corporation Dilemma' was also raised by some regulators who struggled to understand the complete mandate of the utilities they were regulating. Specifically, there were some concerns about providing a fair and balanced view of costs, when government was delivering social policy agendas through the utility. This was identified as an issue by some, but not all, jurisdictions where the regulator was working with Crown Corporations. Again, this concern is addressed by establishing clear definitions for the metrics proposed and allowing for the collection of demographic data that will demonstrate the differences. Also, the comparisons would not be viewed in isolation of other local factors and variations in utility structures.

More information on individual jurisdictions' views on the concerns of using benchmarking can be found in Appendix F.

6.1.2 Challenges for the Regulator

The process of collecting data to begin establishing a benchmarking framework will pose many challenges for regulators – some practical, some conceptual. There are logistical challenges associated with collecting, compiling and presenting the large amount of data which will need to be collected as well as the question of data quality and analysis. But more important perhaps, is the way this data can and will be used in the regulatory process. The types of challenges we foresee are grouped in the list below.

- Data quality and consistency
- Data gathering and recording process
- Comparability for cross-jurisdictional benchmarking
- Integration into current regulatory processes

6.1.3 Data Quality and Consistency

Data quality is paramount to the success of a benchmarking process. Using clear definitions will assist in creating standardized data collection, but there is still the need to ensure comparability of the data presented and how any variations should be taken into account in the analysis. For example, a combined generation, transmission and distribution utility will need to allocate costs associated with the generation component which is outside the scope of this study. As such, the relative costs will be shared over a larger group of services and may therefore seem lower than a utility which is focused on electricity transmission and distribution only.

The relative merit of metrics must also be considered. Data availability across all jurisdictions will limit what it is possible to collect initially. As such, metrics must be divided into nice to have and need to have. Those in the second category will allow regulators a robust view to the utility performance, but may not provide enough information to diagnose differences or shortfalls. Metrics identified as nice to have would be useful to further explore differences in utility performance, but they may not be available in the short term. Or alternatively, they may not be applicable to all utilities. In the final analysis, the metrics presented will create a consistent picture of each utility, and reduce the amount of additional information that will need to be collected to explain them. However, each metric will be open to some interpretation, and these differences will create the range of results which will ultimately generate a set of values for the standards.

6.1.4 Data Gathering and Recording Process

In order to have an effective and efficient data collection process, it is ideal to have a single entity collect and compile the data. A central body could assemble the data submitted by utilities across Canada and present the findings in a single national data inventory. There are a number of practical considerations which need to be addressed for the data collection process.

In order to ensure consistency, a survey instrument will need to be designed that provides utilities with a template to present their results, along with definitions and an area to document the demographic characteristics. In addition, a one-time characterization of the utility which will provide them the opportunity to identify other factors which may affect comparability of performance would be included in the initial data collection process. These survey instruments could be included as part of the regulatory filing in each jurisdiction, which means materials would be submitted to each individual regulator, who would review for completeness and accuracy and forward to this central body for presentation. Although this approach creates an extra burden of review for the regulator, it is only at the local level that this preliminary assessment can be conducted.

This central body would compile the data across jurisdictions into a database or series of spreadsheets that act as a data warehouse and begin the analysis process. Initially, the analysis will consist of compiling the individual values and presenting a range of results without identifying any Peer Groups. Once this information becomes available publically, as a compilation of results, individual utilities will want the opportunity to provide commentary on their standing and what factors affect their performance.

Over time, the central body could evolve the process using economic analysis to establish Peer Groups and open the discussion for national panels of regulators and utilities to come together and explore best practices.

6.1.5 COMPARABILITY FOR CROSS-JURISDICTIONAL BENCHMARKING

When it comes to data analysis, comparability across jurisdictions will be key. Equivalencies will need to be created to explain differences in both the structure and operating environment of these utilities. The review of demographic characteristics will help somewhat to create standards or ratios of values, however an accompanying description of the regulatory environment, utility structure and government mandate will need to be included as an addendum to the analysis to address the qualitative differences. A regulator using the study results will need to understand where the utility stands in the range, why the company is in that particular quartile and what distinguishes this utility from those that are in the other quartiles. It would not be possible or appropriate in this early stage to simply demand a higher ranking or penalize a utility for landing in a lower quartile.

More mechanistic studies attempt to use economic analysis to normalize away differences in individual utilities, however such studies reduce the transparency of the information and add an extra level of complication that is not needed at this stage. Regulators at the provincial and territorial level will benefit most by simply observing the results from other utilities and using the information presented to gauge what types of questions can and should be asked of their local utility. As an information tool, and a way to begin exploring best practices, a simple inventory of metrics will create value to regulators immediately.

6.1.6 INTEGRATING INTO CURRENT REGULATORY PROCESS

In order to be most effective, these metrics need to be collected for comparison purposes. Our review of current filings identified that much of this information is currently available to regulators through standard filing requirements. However, our preliminary review identified that definitions varied slightly from jurisdiction to jurisdiction. Practically, they are likely to vary even more with the jurisdiction as utilities interpret these requirements and overlay them on the ways the information is collected in their system today. It is theoretically possible to extract this information from current filings, but we recommend creating a dedicated data collection process.

Key to the success of implementing this dedicated process is including it in regulatory requirements for each jurisdiction. Thus utilities will realize the importance of this exercise for the regulator, and make sure to give it the attention required to ensure consistent and timely delivery of information.

They will need to be afforded the opportunity to comment on their standing, which goes to the question of how the report is used and shared. Getting agreement on the metrics and providing the opportunity to be challenged in multiple jurisdictions across Canada will pose additional barriers. The task is not insurmountable, but as the single-company example in Alberta indicates, getting a large number of parties to agree on the right course of action will be difficult and probably take several years (at a minimum) to achieve. This assumes that the ultimate objective is to use this data to establish financial rewards or penalties for performance. However, many of the regulators interviewed identified that the study could be used for information only, at which point stakeholders would have the opportunity to comment on the scope and nature of particular metrics but CAMPUT could proceed with creating the data inventory.

There is also the legal concern associated with defending the approach in regulatory hearings across jurisdictions in Canada. Whether the data collected is used for information or ratemaking, utilities and intervenors will want the opportunity to comment on the content, the approach and the process. Selected regulators interviewed were very concerned about these implications. As CAMPUT moves forward with benchmarking, it is essential to set up a series of stakeholder review sessions, early in the process to allow formal comment on the recommendations.

The process of establishing national roundtables for the discussion of benchmarking will in itself provide value to regulators. It will offer an opportunity to discuss how regulators foresee using the data in the future, and allow utilities to provide recommendations for improving the process.

6.2 UTILITY PERSPECTIVE

6.2.1 CHALLENGES FOR THE PARTICIPANTS

There are many challenges to successful benchmarking and reporting under the best of circumstances, when all participants have "pure" motives for benchmarking. In a situation where benchmarks and performance indicators might threaten the economic results for a given utility or class of utilities, there are many areas of concern; we have placed these challenges into several major categories:

- Motivation/Cooperation limitations

- Inability to track and report statistics
- Definitional inconsistencies
- Differences in demographic circumstances

6.2.2 Motivation/Cooperation Limitations

Where companies are working together to develop and implement a benchmarking process in order to help all of them make performance improvements, and where the results are not used by outside parties to publicly rank them or assess their performance, the greatest opportunity for success exists. All companies in that situation have the same goals – to find appropriate performance metrics, investigate best practices, and help themselves to improve performance and apply better practices. In those situations, the debates tend to revolve around which metrics best indicate performance (and these can be spirited debates) for utilities, and how to capture and compare results.

In situations where the results can have negative consequences for a participating company, there are motivations to skew the results to be more positive. In a regulatory setting, where a poor performance result will translate to penalties of various types, there will be strong motivations to modify the measures to those which are most positive for your own utility, and to craft the definitions for data categories to be most favorable to your own situation. That alone makes it difficult to select a uniform set of metrics and definitions for use by all utilities (and regulators).

Where comparative performance reports serve as the basis for rewards and penalties, there are strong motivations to "cheat". There have been publicly-reported incidents in which employees of utilities were found to have falsified information about customer satisfaction results in order to achieve certain targets for the companies (and upon which individual employee bonuses were based). That possibility exists anywhere the rewards and penalties are substantial.

At the outset of implementation of a benchmark regime, it will be important to work slowly, and test the results to be sure they are achieving accurate, fair comparisons among companies, prior to using the results in ways that have substantial impacts on the financial results for the utilities.

6.2.3 Inability to Track and Report Statistics

A key difficulty in any benchmark study is the effort involved in capturing and reporting specific measures of performance. For most large, sophisticated utilities, this is not a major problem, because they have the resources to put in place data capture and reporting tools. For many smaller utilities, however, there are real limitations on their ability to gather and report metrics at all levels.

This is one of the drivers for a benchmark comparison that argues for a minimal listing of key performance metrics, so that the burden of collecting the information is not greater than the value in doing so. To the extent that measures are kept to a high level of aggregation, the issue is minimized. The greater the level of detail desired, and the more levels down within the organization the measures go, the more likely it is that more and more utilities will have difficulty in reporting all the desired metrics.

An example would be useful here. Safety metrics are universally collected for utilities across Canada and all of North America. The key measures of incident frequency and lost-time incident frequency are tracked by almost everyone. If companies are asked to report for the whole company, they can do it. If they are asked to report separately for the entire distribution and transmission organization, most can do it. If they are asked to produce separate reports for different geographic divisions within the distribution and transmission organization, many can do that. If they are asked to separate out the results for field workers versus engineering workers, fewer can do it. If they are asked to report separate results for construction versus maintenance field workers, even fewer can do that.

As the example points out, at the higher levels within the organization, reporting is relatively simple and accessible, but the farther down the measures are broken out, by organization, by geography, by functional group, etc., the more difficult it becomes to have comparable data across a wide array of utilities. This is true for many different classes of measures and many different functional areas.

6.2.4 Definitional Inconsistencies

For the benchmark studies that utilities routinely participate in on a voluntary basis, with the goal of sharing information and helping each other to perform better, one of the critical issues discussed in depth is the definition of each measure of success. As was explained in Section 5 on Standards, the definitions and calculation approaches used in comparing results vary from company to company. For any of the industry benchmark studies in place today, much of the annual planning discussions revolve around the appropriate definitions of various metrics, and the costs or activities that should be included. In order for the results to be highly useful, it is imperative that the definitions are consistent across the utilities, and achieving that is difficult.

In the case of use of benchmarks in regulatory circumstances, where there are strong motivations to achieve certain outcomes, the debates about the appropriate definitions of metrics become much more heated, and the importance placed on having the definition that "you want" becomes much greater. A recent example can provide an illustration. In Alberta, the retail utilities are expected to deliver their customer care services at competitive market prices. One way to determine the market prices is to perform a benchmark study of the prices across the industry for the customer care services. One of the retailers has been instructed to perform a collaborative benchmark study to determine the Fair Market Value (FMV) of the collection of services that is agreed to be the "customer care" services.

The guidance from the regulator was given almost three years ago, and in the ensuing period, the parties involved in the study have not been able to agree on the definition of "fair market value", nor on the right metrics to use or what cost elements to include for the study. Depending on how FMV is defined, the results of the benchmark study will either be favorable or not favorable for the individual retailer. The net result is that the study has not yet been performed, and two rates cycles have passed in the intervening period while the parties have been debating the definitions.

If the long-term goal of regulatory benchmarking is to have comparable metrics that can be used across jurisdictions (i.e. across all of Canada), it will be important to choose a small enough number of metrics that the inevitable debates about definitions can be held to a manageable level. Some of the debates will be simply because utilities won't want to change the metrics they already use and are comfortable with, or that they honestly believe that one definition is more useful than another. Others will be focused around self-interest of the utilities in making sure the metrics and definitions used will put them in the most positive light. In any event, this specific area is likely to be the most difficult hurdle to get over in the long run.

6.2.5 DIFFERENCES IN DEMOGRAPHIC CIRCUMSTANCES

It is a fact that different utilities face very different demographic circumstances in their service territories. These differences include density of the service territory, prevailing weather patterns, geography (mountains versus plains), level of exposure (e.g. salt contamination near oceans), as well as differences in demands of their customer bases. These demographic differences have significant impacts on how the electric systems are designed for each utility, and therefore on the performance results (costs and reliability, among others).

The demographic differences create benchmarking challenges in two major ways: using appropriate normalizers for performance metrics, and selecting appropriate peers for comparisons. In both cases, there are ways to improve the validity of the comparisons by making the right choices, and the companies will be highly invested in assuring that the "right" choices are made.

At the simplest level, comparing one utility against another requires the use of metrics that are normalized to remove major differences. For example, in comparing costs of two utilities for their distribution operations, it would be silly to compare the total cost of one versus the total cost of the other without normalizing. Un-normalized, all that would be determined would be which utility is larger, and therefore spends more money. Typically used normalizing variables include the number of customers, the number of kilometers of line, the assets in place at each utility. For most utilities, using any of those three normalizing variables will result in similar rankings of the two example companies. In a few cases, however, they might result in very different rankings. A highly-urbanized utility will have a compact service territory, with many customers and few kilometers of line. A very rural utility will have a low customer count, and many kilometers of line. Hence a comparison of those two utilities would result in very different rankings when normalized by kilometers versus customers.

The preceding example illustrates the need to have more than one way (normalizing variable) to compare utilities on the same basic element (e.g. cost), and to choose the most appropriate ones for each utility. It also shows how selection of a set of comparison utilities can make a substantial difference to the results. Comparing a very rural utility to a set of highly urbanized ones would be inappropriate without normalizing the metrics being used.

Normalizing variables can be used to adjust for demographic differences and make appropriate comparisons, but only within reasonable limits. Further, the utilities (and regulators) need to be able to understand logically how the comparisons are fair in order to believe in the results, and extreme normalizations make that difficult. The easiest of situations to deal with is to select peer panels of utilities with very similar demographics, and then use metrics that fit those utilities best for comparison. Then companies can be expected to feel as though they have been treated fairly, and the results will be better accepted. In order to do that, however, it requires that an appropriate peer panel can be established for each utility, which will be a stretch in at least a few cases.

6.3 IMPLEMENTATION CHALLENGES

Now that we have explored both regulator and utility concerns about benchmarking as a construct, it is also important to understand the requirements of benchmarking as a process. There are a number of very practical implementation considerations that need to be addressed early in the discussion, to ensure that appropriate guidelines and processes are established from the beginning to ensure effective implementation.

6.3.1 DATA COLLECTION AND STORAGE

In order to have an effective set of benchmarks, there is a need for clear definitions, and an understanding of the range of acceptable results. But beyond the inventory of the measures themselves (as defined in Section 5), there are issues of data availability, storage and use for comparison.

- **Availability of data** – Section 2 identified the type of information that is collected through regulatory filings in each of the jurisdictions. In order for any broad-based industry study to be effective, it is essential that the data is collected with regular frequency, in a relatively transparent process, that allows for ease of execution and a clear understanding of what is included in each value. By incorporating the metrics into standard filing requirements, the process ensures accuracy and effectiveness of the data collection process.
- **Storage and use of information** – for reasonable comparators to be established, data needs to be housed centrally, and accompanied by a set of guidelines for use. Even with this process established, there will still be a need to apply judgment on the part of

regulators. Unlike the U.K., Canada has a large number of non-homogeneous utilities, so that even simple KPIs may look considerably different across provinces and territories.

- **Presentation of results** – in order to allow for a valid range of results or standards to be established, benchmarking results need to be collected centrally, and presented with the relevant geographic or jurisdictional differences. Thus metrics may need to be presented in a yearbook format accompanied with the relevant caveats for utility-specific differences. The use of demographic identifiers, discussed in Section 5, will also help provide a context for relevant comparators.

In Section 2 we established that a great deal of data is publically available and collected by regulators for information purposes today. A review of Table 1 identifies that there are a consistent set of metrics that are readily available in many jurisdictions across Canada today.

6.3.2 Analysis and Presentation

A review of the application of benchmarks would not be complete without a consideration of the operational implications of implementation. Specifically considering issues of who will compile the data and how it will be used.

Consideration needs to be given to the following questions:

- Would the data be publically available?
- Who should be responsible for producing the metrics?
- What is the role for CAMPUT?

If the data are publicly available, it is simple enough to have regulators produce the data and compile the results in each jurisdiction. Having the data filed individually in regulatory hearings is different from providing access to the compilation of the findings. However, if it is anticipated that this information would be used and addressed in regulatory proceedings, provision should be made to produce a document that can be filed into evidence allowing sufficient opportunity for utility and intervenor review and comment.

Even with relatively clear definitions for a benchmarking study, the data needs to be compiled by someone who is familiar with what is specifically captured in each area. The best example of this is cost data. Without a detailed audit at the account level, it is not always easy to understand cost allocation practices inside a company and how they might differ from those of utility peers. Thus, it is most reasonable to have the individual utilities compile and present the KPIs to regulators. Although this will not avoid the reality of hidden objectives (like social programs being delivered by utilities), it will provide an opportunity to present the rationale for why costs may seem unreasonably high relative to similar peer review companies.

Once the metrics are collected, the values could be used to develop ratios of results by jurisdiction, to create a data inventory with participation from utilities across Canada. Ratios (or grouping of like results) would be most relevant in those jurisdictions, like Ontario, which would otherwise produce a large number of results and could potentially skew the national findings. By compiling a set of metrics, regulators will develop an inventory of data that can be used to conduct trend analysis and identify variations in performance by region, and over time.

CAMPUT could take on the role of ownership of the data inventory. Once the data inventory is established and data have been collected for a few years, analysis can be conducted to determine reasonable ranges of value, by measure. The findings of this analysis would then be used to launch the equivalent of a broad-based industry study. Although this data would originally be used for information purposes only, as trends emerge over time, regulators may begin to contemplate how to apply knowledge created for ratemaking purposes. It is important to note that it would not be reasonable to expect this during the early years of data collection. It would be completely reasonable, however, to use the information collected to probe into the performance of individually utilities, especially those who are clearly delivering results that appear to be outliers.

6.3.3 Evolving the Regulatory Framework

Although it may be an longer-term goal to use benchmarking for rewards and penalties in the regulatory process, CAMPUT is in the early stages of data collection and analysis. It would be premature to consider applying financial implications for utilities based on an initial set of metrics being collected for information purposes.

As the list of metrics is expanded, and the differences in utility characteristics are explored and documented, it may be possible to establish a formal set of Peer Groups. As the impact of the similarities and difference for these Peer Groups is translated into operational implications, it may be possible, over time, to begin to consider a range of standards for each metric, by Peer Group. After these standards are created, the next step is to consider factors for performance improvement.

The process will need to be documented, tested and allowed to evolve based on feedback from regulators, utilities and other stakeholders. As the data collection and analysis process matures, there will be an opportunity to begin to consider how to attach rewards and penalties based on these standards. However, due to the nature of the Canadian regulatory environment, the size, number and distribution of utilities, and the variations in their operating environment, it will be difficult to establish cross-jurisdictional guidelines for performance that can easily be defended in the regulatory arena.

7 A Recommended Framework for Application of Performance Indicators for CAMPUT Members

Through the course of the study, we have observed that a great deal of information is available and being collected today by regulators in Canada. A simple set of benchmarks can be created, using the information currently provided in annual filings. However, there has been no national approach to data collection and reporting. As CAMPUT approaches the introduction of benchmarking in Canadian regulation beyond the list of metrics themselves, an important step will be to create a process to collect and present a simple set of metrics from all utilities and jurisdictions across Canada.

The U.S. has been successful in implementing comprehensive data collection through FERC. As can be seen in Appendix H, the Form 1 instrument is cumbersome and labour intensive to complete leading to additional staffing requirements and increased costs. Coming in at over 200 pages, it has required modifications to utility system and processes to ensure that data is presented in the required format. A modified or simpler data collection instrument can be designed to capture the basic metrics presented and ensure that the information is in a standard and consistent format.

This section identifies the steps to be taken for implementing what is possible in the short term and some ideas for long term enhancements.

7.1 Implementing the Benchmarking Process

A great deal of discussion has surrounded barriers to implementing benchmarking for Canadian utilities. It is true that the current state of the industry does not lend itself easily to a quick implementation of full blown benchmarking, but a number of changes can be undertaken immediately with a plan in place to expand over the longer term. We are recommending a three-phased approach to the implementation of benchmarking.

PHASE 1: BUILDING SUPPORT AND CONSENSUS

- *Define the process for data collection and review*
- *Present metrics for discussion and comment*
- *Set up national roundtable discussions on benchmarking*

PHASE 2: DATA COLLECTION AND SUMMARY

- *Establish data collection instruments*
- *Modify regulatory reporting requirements to include in each jurisdiction*
- *Compile and present initial results*

PHASE 3: ANALYSIS AND EVOLUTION

- *Begin analysis and development of Peer Groups*
- *Establish regulator broad-based industry study*
- *Expand metrics and consider how to include in ratemaking, audit, etc.*

Phases 1 and 2 are part of the short term approach to implementation of benchmarking. Although individual jurisdictions (like British Columbia, Alberta, Ontario and Quebec) may have had discussions with utilities and stakeholders on the relative merits of benchmarking, CAMPUT is now looking at a national approach which will require additional reviews.

Phase 3 will require a longer planning cycle and additional involvement of stakeholders. As both regulators and utilities become familiar with the information collected, benchmarking efforts can continue to be enhanced.

7.2 SHORT TERM APPROACH

In order to establish the basis for benchmarking, a number of metrics have been presented that regulators could begin collecting immediately. While the stakeholder sessions are in progress, CAMPUT could finalize the design and development of data collection instruments and the data warehouse construct. Within the next 12-18 months, CAMPUT could initiate data collection for tracking and reporting purposes. This would allow both regulators and utilities to determine the level of effort and value of proposed information.

This would provide regulators the opportunity to modify their filing requirements to include this new information, and utilities the opportunity to establish internal processes to collect and report in the required format, according to the established definitions. The list of required metrics will start small – focusing on customer care, reliability, asset management, and related costs. Those utilities that are able should be encouraged to provide the additional metrics that are presented as Optional in Section 5.

Table 9: Snapshot of Areas for Measurement

Customer Care	Reliability	Asset Management	Costs	Optional
• Call Centre • Billing • Customer Complaints	• SAIFI • CAIDI • SAIDI	• Asset Replacement Rates (three year), for Distribution, Transmission and Substation assets	• Customer Care • Bad Debt • O&M (both transmission and distribution) • Corporate Services	• Safety • Line Losses • New Services • Conservation

These metrics are being proposed because they are readily available, easy to measure consistently and provide a concise snapshot of the overall performance of the utilities. The optional metrics are included for consideration, because these metrics provide additional insight into utility operations and address a few of the issues of concern raised by specific regulators.

As the data collection is underway, CAMPUT can begin the design and development of information in a yearbook-style annual report so that there is a process in place to compile the data and conduct some preliminary analysis when the information becomes available.

7.3 LONG TERM ENHANCEMENTS

When the analysis phase of the benchmarking is underway, CAMPUT could begin to consider creating Peer Groups to establish guidelines for best practices and identify what is possible for a range of results in these sub-segments of utilities. Creating dialogue will encourage support for benchmarking and deliver a better understanding of the value of benchmarking for both regulators and utilities.

We recommend that CAMPUT sponsor a full-scale industry study. By supporting the development of a broad-based industry study – similar to the studies that utilities participate in today – CAMPUT will ensure that the information collected and the supporting review and documentation is designed to meet the specific requirements of regulators. It has been established in earlier sections that although there is some common ground, regulators' needs are different from those of the utilities themselves. By conducting a broad-based industry study, CAMPUT can bring together regulators and utilities to discuss how data is collected, how standards are developed and how benchmarking can be used in the regulatory environment.

Finally, as the data collection process evolves, regulators could begin increasing the number of metrics collected by either expanding the number of metrics collected in the core areas or introducing additional optional areas for data collection. Metrics within the core areas could be expanded to provide additional insight into particular areas of performance to help identify what those utilities that are at the top end of the range are doing relative to those with lower performance results. This could be done by collecting additional metrics, further exploring best practices at the Peer Group level, or a combination of both.

Alternatively, the range and type of metrics collected could be expanded beyond the five categories presented in Table 9 above. This would allow Canadian regulators to move closer to the comprehensive set of metrics that probe the performance of utilities in all functional areas. This would bring Canada further in line with the level of detailed information collected by international regulators.

The types of metrics that would be considered as expansion of the "core areas" are more detailed versions of some of the currently-proposed metrics. Examples would include such items as the cost of vegetation management, or the number and duration of outages caused by trees on the distribution system. Other cost metrics could explore the unit costs for installation of various system components, from new services to transformers to substations. These would give regulators a better insight into some of the critical elements driving costs and service levels across distribution utilities.

In the realm of expansion beyond the five categories already suggested, example metrics would include environmental performance, employee-related measures such as safety, satisfaction, etc., and service metrics such as accuracy of restoration time estimates, or response time to requests for field visits. A broad array of such metrics is in use by utilities as they strive to manage their business in the most effective way.

Both types of expansion will need to be considered, but in a multi-year planning environment. This approach would allow time for discussion and review of the value of current standards and what additional information is required. A gradual approach would also allow utilities to understand future information needs, and the time to modify their systems for the new information requirements.

With an inventory of metrics, regulators could begin to view additional information and consider their application in ratemaking. Much of the data collected today is used for audit or compliance purposes. Moving to an industry-style study would expand the information available to regulators for reporting purposes, but there are still a number of hurdles to be overcome before benchmarking can be used in ratemaking and other regulatory processes.

Although a mechanistic approach to ratemaking would simplify the process and create consistency across all jurisdictions in Canada, it would be inappropriate to assume that the regulators' judgment and balance will not play a central role. This addresses the traditional debate between precision and streamlining. Using benchmarking to create a streamlined approach to ratemaking could address simpler issues, freeing up regulators time to address more pressing policy concerns within and across jurisdictions. Although a mechanistic approach may be desirable, the precision that comes from a comprehensive review is still required, at least while embarking in the early phases of this journey.

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APPENDIX A: GLOSSARY OF TERMS

The list of terms included is divided into two categories:

- **T&D** which includes terms specific to transmission and distribution benchmarks and
- **Customer Care** which includes terms specific to types of benchmarks used to define service levels and requirements, generally in outsource relationships.

The definitions in this appendix are primarily drawn from the benchmark programs executed by First Quartile Consulting in the areas of T&D and Customer Service. The metrics recommended in Chapter 5 of the main report rely on the definitions in this appendix. The appendix is more comprehensive than the set of metrics listed in Chapter 5, and is indicative of the volume of terms that can become involved in a large-scale benchmarking process.

GLOSSARY OF TERMS – TRANSMISSION AND DISTRIBUTION

The following is a list of relevant definitions for Transmission and Distribution.

Automatic Outage (TADS): An outage is triggered by an automatic protection device, resulting in a normally in-service element that is not an in-service state; e.g. there is a partial or full loss of continuous power flow through the element to the system. A successful AC single-pole (phase) reclosing event is not an automatic outage.

Breakers: A circuit breaker is an automatically-operated electrical switch designed to protect an electrical circuit from damage caused by overload or short circuit. Unlike a fuse, which operates once and then has to be replaced, a circuit breaker can be reset (either manually or automatically) to resume normal operation.

CAIDI: The Customer Average Interruption Duration Index (CAIDI) is a reliability index commonly used by electric power utilities. It is related to SAIDI and SAIFI. CAIDI gives the average outage duration that any given customer would experience. CAIDI can also be viewed as the average restoration time. CAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003 the median value for North American utilities is approximately 1.36 hours.

Captive Muni or Other Transmission Customers: A term developed years ago when there wasn't open access for energy sales. It includes the number of customers that are served by any municipal utilities that you provide all the transmission for. The issue is to understand the number of end-use customers served by the transmission network, even though they may not be distribution customers.

Circuit Mile/Kilometer: Physical miles/kilometers of line multiplied by the number of circuits.

Circuit Sustained Outage Frequency Mileage Adjusted: # of sustained outages per 100 circuit miles per year Circuit Miles; Formula: (Total circuit automatic Outages*100)/Total Units:

Clearance order: A request for a line to be out of service.

Customers beyond the meter: This is focused on master-metered buildings, such as apartments.

Customer Interruption Causes for Distribution: The following are definitions for typical causes of customer interruptions.

- **Major Events** - Customer interruptions during major events.
- **Planned Interruptions** - Customer interruptions due to planned (non-emergency) events.
- **Trees** - Customer interruptions caused by trees or other vegetation.
- **Weather related [ex lightning]** - Customer interruptions caused by inclement weather, other than major events.
- **Lightning** - Customer interruptions caused by lightning, other than major events.
- **Animals** - Customer interruptions caused by animal contacts.
- **Distribution Equipment Failure** - Customer interruptions caused by equipment failures on the distribution system.
- **Acts of Public (Autos, Dig-ins, Vandalism, etc)** - Customer interruptions caused by acts of the public, such as vehicle contact with company distribution facilities, dig-ins, vandalism, etc.
- **Substation Outages** - Customer interruptions caused by outages originating "inside the substation fence".
- **Transmission Outages** - Customer interruptions caused by outages originating on the transmission system.

Days Away, Restricted, or Transferred (DART) Rate: This includes cases involving days away from work, restricted work activity, and transfers to another job and is calculated based on (N/EH) x (200,000) where N is the number of **cases** involving days away and/or job transfer or restriction, EH is the total number of hours worked by all employees during the calendar year, and 200,000 is the base for 100 full-time equivalent employees.

Direct labor: This includes: linemen, crews, electricians, troubleshooters, engineers, designers.

Distributed Storage: Use of devices at various locations to store electricity for use when demand exceeds supply.

Distribution End-Use Customer: An entity (usually defined as a metered point of delivery) who receives electric distribution services. Does not include customers connected through an LDC.

Distribution Lines and Substation Operation Expense: Typically includes the following items (580) Operation Supervision and Engineering; (581) Load Dispatching; (582) Station Expenses; (583) Overhead Line Expenses; (584) Underground Line Expenses; (585) Street Lighting and Signal System Expenses; (586) Meter Expenses; (587) Customer Installations Expenses; (588) Miscellaneous Expenses; (589) Rents. The above list is directly from a FERC form and shows what is normally included in FERC. Meter Reading is not included in Distribution Operation expense.

Distribution O&M Expense: Includes trouble calls costs; meter change-outs, installations and other meter shop activities. Does not include meter reading. Field service not included: disconnect/reconnect, etc.

Distribution Plant in Service and Plant Additions: Typically includes the following items (360) Land and Land Rights; (361) Structures and Improvements; (362) Station Equipment; (363) Storage Battery Equipment; (364) Poles, Towers, and Fixtures; (365) Overhead Conductors and Devices; (366) Underground Conduit; (367) Underground Conductors and Devices; (368) Line Transformers; (369) Services; (370) Meters; (371) Installations on Customer Premises; (372) Leased Property on Customer Premises; (373) Street Lighting and Signal Systems; (374) Asset Retirement Costs for Distribution Plant.

Distribution Voltages: For purposes of this report, we define distribution to be a voltage level of 45kV and below. The distinction is somewhat arbitrary, but picks a point between 69kv which is generally considered a transmission (or at least sub-transmission) level and 21kV which would generally be considered distribution. It is unrealistic to ask utilities to redefine their cost or reliability reporting on the basis of these definitions. However, a utility that has very different definitions may want to restate these statistics to better compare their performance.

Element (TADS): The following are elements for which TADS data are to be collected: 1) AC Circuits>= 200kv (overhead and Underground); 2) transformers with >= 200kv low side voltage; 3) AC/DC Back to back converters with >= 200kv AC voltage on both sides; 4) DC circuits with >= 200kv DC Voltage.

Element Availability Percentage: *Formula*: 1- (total sustained outage hours/total element hours) * 100; Acronym: APC; 1QC Variation: Similar to Circuit Availability with (voltage and element restrictions) but does not include planned outages.

Element Momentary Outage Frequency: *Formula*: Total Momentary Outages/ Total Elements; *Units*: # of momentary outages per element per year.

Element Sustained Outage Duration Time: Total Sustained Outage Hours/Total Elements; *Units*: # of automatic outage hours per element per year; Acronym: SODT; 1QC Variation: Similar to Average circuit unavailability (aka SAIDI), but has same differences in elements and voltage levels.

Element Sustained Outage Frequency: Total Sustained Outages/ Total Elements; *Units*: # sustained outages per element per year.

Element Sustained Outage Mean Time to Repair: Total Sustained Outage Hours/Total Sustained Element Outages; *Units*: # of automatic outage hours per element outage per year.

Element Total Automatic Outage Frequency: *Formula*: Total Automatic Outages/ Total Elements; *Units*: # of automatic outages per element per year; *Acronym*: TOF; Similar to outage frequency with the following differences: elements definition is not quite the same as circuit (e.g. a transformer outage is counted as an outage); only applies to elements >=200 kV; excludes outages not triggered by automatic protection devices (e.g. outages initiated by the operations center, usually "planned" outages); includes momentary and sustained outages.

Energy Control Center Expense: The O&M expenses associated with operating a transmission control center(s). This would be a subset of the Transmission O&M expenses. It is most likely to be found in FERC account 561, Load Dispatching, but it might be in other places.

Extraordinary Items: Unusual costs such as related to extreme weather events (Ike, Katrina).

Facility Point: Units maintained such as Pole and the equipment attached to it.

FERC Distribution Lines and Substation Maintenance Expense: (590) Maintenance Supervision and Engineering; (591) Maintenance of Structures; (592) Maintenance of Station Equipment; (593) Maintenance of Overhead Lines: (594) Maintenance of Underground Lines; (595) Maintenance of Line Transformers; (596) Maintenance of Street Lighting and Signal Systems; (597) Maintenance of Meters; (598) Maintenance of Miscellaneous Distribution Plant.

Field: Groundmen: Supports crew in non-electrician role; includes classifications such as groundman, helper, and equipment operator.

Field: Substation Crew Members: Skilled electrician who performs operations, construction and maintenance work in substations; may perform at several skill levels (apprentice, journeyman, lead, working foreman). Also includes crew members in non-electrician roles such as groundman, helper.

Field: Substation Operators: Electricians assigned primarily to operate substations in the field; may be assigned to a substation or an assigned territory.

Field: Transmission Linemen: Skilled electrician who performs operations, construction and maintenance work on the transmission system; may perform at several skill levels (apprentice, journeyman, lead, working foreman); may work on overhead and underground work; allocate transmission.

Field: Transmission UG Cable Splicers: Linemen assigned to work full time on the UG system.

Field: Troubleshooters: Lineman assigned full time to perform switching (line devices and usually substation breakers) and to respond to outages on the electrical system (line fuses, line down, customer lights out, part lights out); may also perform meter sets, inspection, and maintenance.

Full-time Equivalent employees: Employees assigned full time to a function. Include full-time supervisors and managers. Or full-time employees who spend part time in different functions. Include part time supervisors and managers. Also include employees who spend less than 40 hours per week. Does not include count of employees for fully-outsourced functions.

Generation Outages - Customer interruptions caused by outages or shortage of supply on the generation system.

Human Error - Automatic Outages caused by an incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. Also, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category.

IEEE Standard 1366: has become the major guide for definitions on distribution reliability. Though not every utility follows exactly, some of the key issues identified by this standard include: Outage duration to be considered an interruption and Definition of a major event (2.5 Beta Method).

Initiative: A new activity, program, or process where success or failure is being tracked.

Intelligent Grid: An intelligent grid uses two-way communication. Data flows in to the utility operation center from all points over the grid, including transformers, SCADA equipment, meters, street lights, traffic/security cameras, and energy management units in the home or business. The utility can also send outgoing data streams to deliver real-time pricing information to customer premises, connect/disconnect meters, or activate load control units.

Interconnections: The number of transmission voltage interconnections with generating plants and electric utilities and also the transmission interconnections with retail customers. This also includes all transmission voltage connections to any other system not owned by the company.

Level 2 Transmission Load Relief: used as an indication of congestion. As defined in Power System Operations and Electricity Markets. The purpose of NERC TLR (Transmission Load Relief) procedure is to define the actions and communications to reduce the flow on a transmission element of the bulk power transmission system. The effect of a TLR level 2 [Hold] is to cause all schedules to hold at the current active flow levels.

Lost Time Incident Rate (illness and injury): Rate for Total Lost Time Incidents (illness and injury) calculated: N / EH *200,000 where N = Sum of the number of recordable [nonfatal] injuries and illnesses resulting in days away from work in a given time frame; EH = Total number of hours worked by all employees in a given time frame (either 1 year for an annual rate or 3 years for a 3-year combined rate); and 200,000 = Equivalent of 100 full-time workers working 40-hour weeks 50 weeks per year. Rate for Total Lost time Incidents calculated: (Total of OSHA 300A Column H) x 200,000) / Total Hours Worked.

Lost Time Severity Rate (illness and injury): Lost Time Severity Rate (illness and injury): (# of lost or restricted days X 200,000) / Total Hours Worked.

Mean time between Sustained Element Outages (mean "Up Time"): Average # of hours of operation of an element before it fails. *Formula*: (Total Element Hours - Total Sustained)/Total Elements.

Median time to repair Sustained Element Outage Failures: The time when 50% of the Mean Time to Repair minutes are greater than this figure; Median # of hours of operation of an element before it fails.

Multi-Circuit Sustained Outage Frequency Mileage Adjusted: # of sustained outages per 100 circuit miles per year. *Formula*: (Total circuit automatic Outages*100)/Total Circuit Miles.

MVA of Transmission substation capacity: This is for both autotransformers and for power transformers with transmission voltage on the high side. It would include some transformers with distribution voltage on the low side.

MW-Miles: For each circuit multiply the number of miles by total peak load capacity defined in megawatts; the sum of all circuits for a voltage class is the total mw-miles for voltage class. Use the transfer capacity of lines as defined in your base-case load flow for peak conditions.

New Business Capital Additions: Capital additions primarily to hook up a specific new customer at the distribution or transmission level to generate additional revenues. Does not include expenditures to replace in kind, to improve reliability, or to meet general increase in system load. Include new interconnections.

New Customers Added to system: Includes new meter set or major panel upgrade, gross, not net.

Number of new interconnections: The number of new interconnections which were built during the year; interconnections to the transmission system at transmission voltage level.

Outage Causes for Substation & Transmission: The following are definitions for typical cause of outages.

- **Weather, excluding lightning** - Automatic Outages caused by weather such as snow, extreme temperature, rain, hail, fog,sleet/ice, wind (including galloping conductor), tornado, microburst, dust storm, and flying debris caused by wind.
- **Lightning** - Automatic Outages caused by lightning.
- **Environmental** - Automatic Outages caused by environmental conditions such as earth movement (including earthquake, subsidence, earth slide), flood, geomagnetic storm, or avalanche.
- **Contamination** - Automatic Outages caused by contamination such as bird droppings, dust, corrosion, salt spray, industrial pollution, smog or ash.
- **Foreign Interference** - Automatic Outages caused by foreign interference from such objects such as an aircraft, machinery, a vehicle, a train, a boat, a balloon, a kite, a bird (including streamers), an animal, flying debris not caused by wind, and falling conductors from one line into another. Foreign Interference is not due to an error by a utility employee or contractor. Categorize these as “Human Error.”
- **Fire** - Automatic Outages caused by fire or smoke.
- **Vandalism, Terrorism or Malicious Acts** - Automatic Outages caused by intentional activity such as shot conductors or insulators, removing bolts from structures, and bombs.
- **Failed AC Substation Equipment** - Automatic Outages caused by the failure of AC Substation; i.e., equipment “inside the substation fence” including Transformers and circuit breakers but excluding Protection System equipment.
- **Failed AC/DC Terminal Equipment** - Automatic Outages caused by the failure of AC/DC Terminal equipment, i.e., equipment "inside the terminal fence" including PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors, and DC filters but excluding Protection System equipment.

- **Failed Protection System Equipment** - Automatic Outages caused by the failure of Protection System equipment. Includes any relay and/or control mis-operations except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices. Categorize these as "Human Error".
- **Failed AC Circuit Equipment** - Automatic Outages related to the failure of AC Circuit equipment, i.e., overhead or underground equipment "outside the substation fence."
- **Failed DC Circuit Equipment** - Automatic Outages related to the failure of DC Circuit equipment "outside the terminal fence." However, include the failure of a connecting DC bus within an AC/DC Back-to-Back Converter in this category.
- **Vegetation** - Automatic Outages caused by vegetation with the following exclusions: (1) Vegetation-related outages that result from vegetation falling into lines from outside the right of way that result from natural disasters shall not be considered reportable with the Vegetation Cause Code. Examples of disasters that could create non-reportable Vegetation Cause Code outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods, and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable under the Vegetation Cause Code. Examples of human or animal activity that could cause a non-reportable Vegetation Cause Code outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Outages that fall under the exclusions should be reported under another Cause Code and not the Vegetation Cause Code.
- **Power system Condition** - Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g. an abnormal terminal configuration due to existing condition with one breaker already out of service).

Peak % capacity utilized for substation MVA: This includes both power and autotransformers.

Percentage of Element Automatic Outages: Associated with Disturbance Report. *Formula*: Total Automatic Outages Elements associated with a disturbance report/Total Automatic outages.

Percentage of Elements with Zero Automatic Outages: *Formula*: Total elements with Zero Automatic Outages/Total Elements.

Practice: An activity, program, or process that has been in place for a time such that it is possible to measure the outcome (success or failure).

Recordable Incident Rate (illness and injury): Rate for Total Recordable Incidences (illness and injury) calculated: N = Sum of the number of recordable nonfatal injuries plus illnesses in a given time frame (either 1 year for an annual rate or 3 years for 3-year combined rate); EH = Total number of hours worked by all employees in a given time frame (either 1 year for an annual rate or 3 years for a 3-year combined rate). 200,000 = Equivalent of 100 full-time workers working 40-hour weeks 50 weeks per year; (N *200,000) / EH. (Total of OSHA 300A Columns G + H + I + J) x 200,000) / Total Hours Worked.

Regulatory/ISO Expense: This is an area of expense that is another subset of O&M expenses for Transmission. It might show up in a variety of different Transmission O&M accounts. It is the charges paid to an ISO for their services to the utility. For some utilities this will be essentially zero. For others, it can be substantial.

Return on investment: The rate of return is the percentage rate which the regulator finds should be earned on the rate base in order to cover the cost of capital (i.e., interest on debt and return on equity) or the cost of service to be recovered in rates, which equals the company's revenue requirements and is often referred to as the cost of service model. The return component is calculated by multiplying the investment in the rate base by an allowed rate of return authorized by the regulator.

Rural: Less than 50 customers per square mile.

Safety Rates: Include office and field. Exclude meter readers and customer service related employees. Exclude employees performing credit-related disconnects/reconnects, high bill investigations, turn-ons/turn-offs.

SAIDI: The System Average Interruption Duration Index is commonly used as a reliability indicator by electric power utilities. SAIDI is the average outage duration for each customer served, and is calculated as: SAIDI = sum of all customer interruption durations/ total number of customer served. SAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003 the median value for North American utilities is approximately 1.50 hours.

SAIFI: The System Average Interruption Frequency Index is commonly used as a reliability indicator by electric power utilities. SAIFI is the average outage frequency for each customer served, and is calculated as: SAIFI = sum of all customer interruptions/ total number of customers served. SAIFI is measured in units of interruptions per customer. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003 the median value for North American utilities is approximately 1.10 interruptions per customer.

SCADA: SCADA is the acronym for Supervisory Control And Data Acquisition. SCADA systems are typically used to perform data collection and control at the supervisory level. Some systems are called SCADA despite only performing data acquisition and not control.

Secondary voltages: defined as less than 1kV.

Stores Loading Rate: a percentage added to the actual cost of a stores item to account for the storeroom cost (storekeeper salaries, storeroom expenses, internal transportation, etc).

Structure Mile/Kilometer: Physical miles of line irrespective of the number of circuits -- structure miles refers to both overhead pole miles and underground trench miles.

Substations: In the U.S., FERC provides a series of guidelines based on function. When two functions exist on the site, they offer the option of splitting substation between transmission and distribution or predominant use. There is a need to split the function and report as both a T and D substation, for the goal is transmission stations that are classified as "transmission" whether it's an auto-transformer or a power transformer. For a station that has both transmission and distribution, it is appropriate to apply a "predominant use" judgment.

Support: Mapping & Records: Technicians who create and maintain design drawings, maps, and records of the distribution system (a.k.a. mappers, drafting technicians, CADD Operators, Records Clerks).

Support: Relay Technicians: Technicians who specialize in installing and testing transmission and distribution voltage relays that primarily are installed in substations.

Support: SCADA Technicians: Technicians who support operation of the SCADA system that usually have primary terminals in substations and control rooms.

Sustained Outage (TADS): An automatic outage with an outage duration of 1 minute or greater.

Transformer failures: A failure is any loss of function that would require the unit to be taken out of service. A diagnostic test that resulted in a planned outage would not necessarily be considered a failure. For transmission transformers, this is regardless of whether they are autotransformers or power transformers.

Transformers: A transformer is a device that transfers electrical energy from one circuit to another through inductively coupled electrical conductors. A changing current in the first circuit (the *primary*) creates a changing magnetic field; in turn, this magnetic field induces a changing voltage in the second circuit (the *secondary*). By adding a load to the secondary circuit, one can make current flow in the transformer, thus transferring energy from one circuit to the other.

Transmission circuits: defined as transmission of 36kv or above; proposing a change to 46kv and above for 2008, including AC and DC circuits.

Transmission Lines and Substation Maintenance Expense: Typically includes the following items (568) Maintenance Supervision and Engineering; (569) Maintenance of Structures; (569.1) Maintenance of Computer Hardware; (569.2) Maintenance of Computer Software; (569.3) Maintenance of Communication Equipment; (569.4) Maintenance of Miscellaneous Regional Transmission Plant; (570) Maintenance of Station Equipment; (571) Maintenance of Overhead Lines; (572) Maintenance of Underground Lines; (573) Maintenance of Miscellaneous Transmission Plant.

Transmission Lines and Substation Operation Expense: Typically includes the following items (560) Operation Supervision and Engineering; (561) Load Dispatching; (561.1) Load Dispatch-Reliability; (561.2) Load Dispatch-Monitor and Operate Transmission System; (561.3) Load Dispatch-Transmission Service and Scheduling; (561.4) Scheduling, System Control and Dispatch Services; (561.5) Reliability, Planning and Standards Development; (561.6) Transmission Service Studies; (561.7) Generation Interconnection Studies; (561.8) Reliability, Planning and Standards Development Services; (562) Station Expenses; (563) Overhead Lines Expenses; (564) Underground Lines Expenses; (565) Transmission of Electricity by Others; (566) Miscellaneous Transmission Expenses; (567) Rents.

Transmission Plant in Service and Plant Additions: Typically includes the following items (350) Land and Land Rights; (352) Structures and Improvements; (353) Station Equipment; (354) Towers and Fixtures; (355) Poles and Fixtures; (356) Overhead Conductors and Devices; (357) Underground Conduit; (358) Underground Conductors and Devices; (359) Roads and Trails; and (359.1) Asset Retirement Costs for Transmission Plant. The above list is directly from a FERC form and shows what is normally included in FERC.

Transmission Line Availability: 1 - (Total Number of Hours Transmission Circuits Were NOT in Service / 8760). Note that a line out for an extended period of time can be excluded from calculation.

Transmission Line Availability: An outage measured in weeks could be excluded from the data. An outage of this generation would suggest that there was an alternate feed or some other alternative supply. Transmission Line Availability 1 - (Total Number of Hours Transmission Circuits Were NOT in Service / 8760). Note that a line out for an extended period of time can be excluded from calculation.

Transmission Substation: Transmission station is one with the high-side voltage at transmission level. For a station that has both transmission and distribution, consider "predominant use" judgment.

Tree: The forestry definition for a tree is a minimum of 4" diameter.

TSAIDI (circuit): The average number of minutes a circuit is out each year.

TSAIDI (POD): The average number of minutes a Point of Delivery is out each year. NOTE: calculation of PODs is not consistent among utilities because of different system configurations, but is intended to be the switch point.

Urban: Defined as areas >250 customers per square mile.

Utilization Factor: Ratio of the maximum demand load to the normal rated capacity of the system for the reporting year. Maximum demand load is defined as the maximum observed load for a particular time interval. (Use your Utility's normal time interval standard for determination). NOTE: this is non-coincident peak demand for each circuit.

Vehicle Incident Rate (preventable and non-) (aka Motor Vehicle Accident Rate): Most utilities report all reportable accidents, whether preventable or not and regardless of fault. In general, should include personal vehicles when used on company business.

Voltage Classes: For transformers, the voltage class reported will be the high-side voltage, even though the cut-off voltage used in the definition is referenced on the low-side.

GLOSSARY OF TERMS – CUSTOMER SERVICE

The following is a list of relevant definitions for Customer Service.

Abandon rate: Percentage of inbound calls abandoned over total incoming calls offered to customer reps. Do not Include calls blocked at switch and/or limited calls if any. Calls abandoned within a reasonable period of time, 5 seconds, should not be counted as abandoned or handled calls.

Accounts: Active accounts in your system. An account is typically used for billing purposes. Accounts are frequently used as the definition of customers.

Adherence (in Contact Center): Pertains to adherence to schedule. Contact Center agents sticking to the schedule established by center management. Includes being on time for scheduled work start, break start, break end, other scheduled actions. Most current scheduling software has reporting tools that can track this in centers.

Administrative support: Unlike technical support, administrative support refers to a task that is required in all processes. It is generic in nature and is (for the most part) interchangeable between functional areas. This category includes all secretarial FTE as well as accounting and reporting decentralized in a specific activity, treatment of basic business information, scorecards, etc.

AMI or SMART Meter: Metering that has a core functionality intelligent, fixed-network style meters with two-way communication that can be read remotely (not including mobile AMR).

Appointment Integrity: Meeting appointments within the appointment window – percentage of time when appointments are met.

Automatic Call Distributor (ACD): Answers calls and puts (routes) the call in a pre-specified order in the line or queue of waiting calls, delivering calls to call handling agents in the pre-specified order. Provides the means to specify the possible variations in the order of calls and agents. Also provides the data for detailed reporting on every aspect of call transactions.

Automated Clearing House (ACH): The name of an electronic network for financial transactions in the United States. ACH processes large volumes of both credit and debit transactions which are originated in batches. ACH credit transfers include direct-deposit payroll payments and payments to contractors and vendors. ACH debit transfers include consumer payments on insurance premiums, mortgage loans, and other kinds of bills. Businesses are also increasingly using ACH to collect from customers online, rather than accepting credit or debit cards.

Average Age of Receivables: calculated as (Accounts receivable at the end of a month x 30)/revenues in that month. To get the true annual average, the 12 monthly figures should be averaged.

Average Hourly Rate: calculated by taking the hourly rate of all employees in that group and dividing by the total number of employees. This should include all FTEs in that particular staffing category whether company or contract. This should only include direct labor FTEs.

Average Speed of Answer (ASA): Average speed of answer for a call answered by a company rep, after the call leaves the VRU. Do not count abandons as completed calls. It is possible to capture both ASA without Self-serve (IVR) and blended with IVR.

Behavioral Scoring: Behavioral scoring is a form of credit scoring used to track the payment behavior of customers after they become customers of the utility.

Bill Counts: Count one per customer, even if multiple commodities or multiple meters at a premise (e.g. a "consolidated bill"). If a summary bill is produced (e.g. usage at multiple locations is summarized), count each individual location as a bill, as well as the summary bill. Count any e-bills sent, but do not double count any mailings. If you send both paper and electronic, count as one bill. Include any final bills sent in this count.

Billing Activities: Include all billing activities regardless of paper or electronic bill. Bill calculation should be included. FTEs handling billing exceptions, bill adjustments, bill calculations, etc. are part of billing organization.

Billing Clerk: Front-line worker who reviews bills for accuracy, and investigates problems with them. Job might include correcting bills before sending to customers, approving them for issuing to customers, or correcting for re-issue following a cancel or rebill.

Billing Engine: Unique system that receives, validates, processes customer billing information in order to bill/invoice the customer. The main CIS would be considered one. Often companies have separate systems to handle special billing, customers or rates.

Billing Error Rate - After Mailing: Account errors or adjustments needed that are identified after the bill is delivered to the customer. A change that affects multiple months is still considered one adjustment. Does not matter if the account is re-billed or just adjusted on a subsequent bill. The adjustment may not be the company's "fault". Errors are anything that need to be corrected. Exceptions include planned manual adjustments.

Billing Error Rate - Before Mailing: Errors found "before" are a subset of sample search or found during pre-bill audit. Errors are anything that need to be corrected.

Billing Issues (in Contact Center): Customer issues related to a bill. Examples include: perceived high bill, incorrect bill, duplicate bill, inability to understand bill, etc.

Blocked Calls: Inbound calls that are purposely prevented ("blocked") from entering the ACD or telecom switch by management discretion or, in some cases, trunk capacity limitations. These calls would not therefore enter the call answering queue and not be seen as offered calls for handling. 1QC adds these in the total abandoned call count as these are calls that distort the true inbound call volume and do not allow the customer to contact the company in the call attempt.

Business Contact Center: For purposes of contact center or call split definition, the business contact center should handle small and mid-range business customers. Should not include Key Accounts or Large C&I customers that may typically have their own assigned account representatives, teams, or group. Companies vary in how they define smaller and mid size customers, some using kW others revenue or meters.

C&I Customers: Commercial and Industrial Customers.

Cashiers: Staff in local offices that only take payments from customers and don't perform any other activity. These employees should be counted as part of payment processing rather than local office.

Call Split: A routing division in the ACD that allows calls of certain transaction types to be answered by specific groups of employees. Also called a group or a gate. Call splits should be measurable.

Service Level: Calls Answered within X seconds: Percentage of calls answered by a company rep within specified time period. Include abandons in the total calls offered (the denominator), but do not include in calls answered (numerator).

Can't Get In (CGI): Field situation where a field worker or meter reader cannot access the premise or meter to do the assigned task. Reasons include: customer not home, no access provided or access blocked, such as a key issue or no keys, meter cabinet locked. May result in a need for a second visit by the worker.

Change of Account: New customers, moving customers, turn-ons/turn-offs due to customer relocation, not due to credit issues.

Check 21: The Check Clearing for the 21st Century Act (or Check 21 Act) is a US federal law that allows the recipient of a paper check to create a digital version, thereby eliminating the need for further handling of the physical document.

Collection Agency: Company to whom customer accounts are assigned for collection, most often after the utility has failed with internal collections efforts. Typically no payments are made unless the agency successfully collects bills. Primary agencies are the first placement of the bad debts, and they are typically allowed a fixed period of time to attempt collections prior to the debts reverting to the utility. Secondary and then later, tertiary agencies are assigned the bills to attempt collection.

Collection Agency Cost: Includes fees paid to collection agencies for collection of overdue bills, whether they are calculated as a % of the bills collected, or as straight charges from the collection agencies. Include any collection agency or skip trace costs in contracted services.

Company Labor Costs: Include Direct, Support, Supervision, and Management.

Consolidated Bills: A bill that shows energy usage as well as charges for other services that the utility offers.

Contact Center: Contact Center and Multi-Channel contacts covers every interaction with customers except Meter Reading, Field Service and Credit Outbound Calling.

Contact Center - Primary and Secondary: Delineation to make in understanding the primary and secondary physical locations a company operates for their contact centers. Primary should be the main, largest or home site or sites, with secondary the smaller or satellite sites that are operated. Both types should be full time and company staffed. Some companies, particularly those in recent mergers may call more than 1 location a “primary” center.

Contact Center Contacts: A completed customer call, local office transaction, IVR, or internet transaction. Does not include uncompleted transactions (e.g. abandons), or general switchboard informational calls.

Contact Center Employees: Include employees in both the call center and local office.

Contact Center Service Measures: These measures should be a blended rate between company and outsourced call answering. They should exclude credit calls.

Contract Labor Costs: Individuals (not firms) contracted to perform a specific role (including temps, seasonal).

Contracted Services Costs: Companies contracted to perform a specific function such as meter reading, overflow call centers, debt collection, etc. or the cost of any contract or outsourcing services. Does not include any capitalized costs for IT services, but does include 3rd party back-up and disaster recovery.

Convergent Billing: Bills with multiple services included, e.g. metered usage, area lighting, cable TV.

Corporate or Corporate Function: Includes functions managed and providing services for the whole of the organization. Examples include: Shared Services, Human Resources, Accounting, Information Technology.

Cost of Employees: includes paid non-working time (e.g. vacation, sick, etc). Does not include labor overheads (e.g. payroll taxes, benefits) or other department's allocated charges. If a supervisor or manager spreads their time over multiple departments, then provide an allocated portion of their costs to the function.

Credit Inbound Calls: Calls from customers to create payment arrangements, make delinquent payments, or otherwise handle overdue accounts. Part of Contact Center costs.

Credit Office Activities: Notices issued, determination of disconnections and reconnections, payment arrangements when handled in the credit area (separate from contact center), outbound calls, policy development and execution.

Credit Outbound Calls: Calls made by the company to remind customers to pay their overdue bills, make payment arrangements, etc. Part of Credit & Collections costs.

Credit Postage: Costs of sending out reminder notices for slow-paying customers. Only include if a separate credit mailing, otherwise put in billing.

Credit Scoring: This is a service purchased from a vendor who maintains credit records on individuals, not specific to utility payment behavior. Typically used at the time when a customer signs up for service with the utility.

Customer Counts: Customer count differences can be measured in three ways:

1 **Accounts**: The number of accounts in your billing system. An account with electric and gas meters gets counted once;

2 **Commodity**: Roughly represents the number of meters on your system. Where an account with both gas and electric would get counted as one account, for commodities it would get counted as two customers. Exceptions: there are unmetered items and meters that are not counted (such as streetlights); and,

3 **Internal**: The count you use internally to represent the number of customers you have. This is the one typically reported on annual reports and other documents.

Customer Service IT: The activities associated with operation and maintenance of the Customer Information System (CIS).

Daily Rate: Terms used in contract design, calculation assumes 250 days per year.

Days Away, Restricted, or Transferred (DART) Rate: This includes cases involving days away from work, restricted work activity, and transfers to another job and is calculated based on (N/EH) x (200,000) where N is the number of cases involving days away and/or job transfer or restriction, EH is the total number of hours worked by all employees during the calendar year, and 200,000 is the base for 100 full-time equivalent employees.

Days Sales Outstanding: A measure of the average number of days that a company takes to collect revenue after a sale has been made. A low DSO number means that it takes a company fewer days to collect its accounts receivable. A high DSO number shows that a company is selling its product to customers on credit and taking longer to collect money. Calculated as average month-end accounts receivable / total annual revenues x total days.

Direct Debit: Customer has arranged with the utility to have their payment automatically deducted from their bank account.

Direct Labor: A person having direct interactions with a customer or with a customer account is considered direct labor. A person whose task is directly in line with the mission of the process. Everyone else is either supervision or support. As a rule of thumb, when the work will affect a customer file or when it has an effect perceptible by a customer or a group of customers, this FTE will be classified as Direct.

Electronic Data Interchange (EDI): The transfer of structured data, by agreed message standards, from one computer system to another without human intervention.

Electronic Funds Transfer (EFT): refers to the computer-based systems used to perform financial transactions electronically. The term is used for a number of different concepts: cardholder-initiated transactions, where a cardholder makes use of a payment card; electronic payments by businesses, including salary payments; and electronic check clearing.

Email/ fax/ letter: Customer contacts initiated through email, fax or letter from the customer.

Estimated Bill: A bill that has been estimated by a billing system using an algorithm stored in the computer system, or by a person, whether it is a meter reader or a billing employee. It is typically based upon previous usage, or usage at similar customer locations. An estimated bill error can be created by a mistake in the algorithm for automated estimates, or by a mistake made by a person in the case of a person estimating the usage.

Extended Shift: Someone who can be placed on an extended shift, longer than 8 hours but should not be included in Full-time.

Field Credit Orders: Credit disconnections and reconnections, notice delivery, field collections. These should be included in Field Service, not in Credit.

Field Service: focuses on activity at the meter and includes: Billing Issues -- High bill investigation in the field, either customer or internally initiated, check read, rereads, meter tests in conjunction with investigation, meter change out in conjunction with investigation; Change of Account; Credit disconnections and reconnections, notice delivery, field collections; Seasonal turn-on/turn-offs; and Dispatch associated with all service orders.

Field Service Billing-related Activity: Includes high bill investigation in the field, either customer or internally initiated, check read, rereads, meter tests in conjunction with investigation, meter change out in conjunction with investigation. Do not include field generated or programmed meter change-outs.

Field Service Order: A completed field order is one where the assigned activity has been performed. CGI or Can't Get In does not count as a completed order. A trip to a service location that involves multiple commodities (e.g. gas and electric change of account) is considered as multiple trips. If multiple activities are performed at a location, count as only one trip.

Field Service Order Assignment: The assignment of a scheduled order to a worker (or work group), geographic territory and skill set. This is the second step in the order management process. It does not include the issuance of the order to a worker and the workers tasks for a day or shift.

Field Service Order Handling/Completion: The last steps in the order management process. The worker handles the issued order and either completes it or updates the status if unable to complete (UTC, CGI etc.) The completion process includes documenting all the appropriate work information required to complete the order for field purposes.

Field Service Order Issuance/Dispatch: The issuance of a scheduled and assigned order to a specific worker or work crew in the field. The best example of an issued order would be an order that is in the hands of the worker (or on his/her mobile device) to be handled and completed.

Field Service Order Scheduling: The scheduling of a specific order to be done at a particular or specified time. This is the first step in the order management process as defined by 1QC. It does not include the assignment of the order or the issuance or dispatch of the order, simply the scheduling. Orders can be scheduled for example as same day, current (with a specific date) or future (known to be scheduled for a future time but without a specific date).

FS Order Assigned: Order has been issued and dispatched to a rep to be completed.

FS Order Completed: Order has been dispatched and the activity assigned by the order has been performed.

FS Order Issued: Order has been prepared but not yet assigned to a representative to be completed.

Full-time Equivalent Employees: Employees assigned full time to a function. Include full-time supervisors and managers. Or full-time employees who spend part time in different functions. Include part time supervisors and managers. Also include employees who spend less than 40 hours per week.

Gas Service (leak, odor, pilot or appliance): Report a gas service leak, odor or request for pilot light.

General Company Information: Get addresses or phone numbers, Annual reports, educational materials.

Get Account Information (view bill, view usage): Get information about address or phone number stored with account. View bill, bill history, usage.

Hard Disconnect: A physical disconnect meaning that one of the commodities is physically turned off.

Hard to Read (aka Hard to access): These are meters that are hard to access and are often missed. They are not the same as meters that are behind locked doors or in basements but to which the utility regularly has access.

Internet/Web Contact: Log-ons to account or hits to a specific type of page. Includes pages that provide information that avoid a phone call.

In-person Contact: Typically walk-in traffic to a local or business office.

IVR (Interactive Voice Response): A telephone interface as a front end to the ACD that allows the customer to enter and gather information from the customer system through either a telephone keypad or spoken word (voice recognition) to complete a transaction. The IVR gives access and takes in information, performs record keeping, and can typically execute transactions.

IVR Call: Is any call handled completely by the IVR over the phone. This is separated between calls handled by company vs. contractor reps.

Limited Calls – Inbound: calls that have passed the ACD but end up disconnecting on the caller after they have passed a call volume threshold. These are not virtual hold calls and are normally not considered abandoned (as they were not abandoned by the caller). 1QC adds these in the total abandoned call count as these are calls that distort the true inbound call volume and do not allow the customer to contact the company in the call attempt.

Live Call: Live call is any call handled by a customer service representative over the phone. This is separated between calls handled by company vs. contractor reps.

Local Office: Local offices are places staffed by utility employees where customers can pay bills or perform other transactions. Typically Local Office is considered an extension of Contact Center. So FTEs, activities, and costs are captured in the Contact Center section of the questionnaire. This excludes cashiers who typically only take payments and are part of the Payment Processing function.

Lockbox: In general, a lockbox is a P.O. Box that is accessible by the bank or outsourcer. A company may set up a lock box service with a 3rd party for receiving customers payments. The company's customers send their payments to the P.O. box. Then the 3rd party collects and processes these payments directly depositing them to the company's account.

Low Income Assistance: Request application, additional information, contact numbers or addresses to sign up for low income assistance.

Manual Payment Processing: Refers to large amounts of payment processing done manually by local office reps or cashiers. Does not refer to one-off types of processing handled by contact centers or when image processing fails.

Major Event: These are typically defined by each utility's distribution department. Often this requires that a large number of customers will be out of service for more than one day.

Materials Costs: All cost associated with the function, including any warehouse/purchasing charges. A few items, such as postage are called out in a separate category. Includes cost of envelopes, paper, and ink. Significant for Billing, Payment and Credit.

Message: Any form of written communication to customers of delinquent status including letters, e-mails, or door-hanger notices.

Meter Read: Scheduled meter reads. If multiple meters are read at a premise, count as multiple reads. Include AMI/AMR, but only count one read per month for billing purposes. Trips to take a reading for a change of account or as part of a billing investigation (e.g. re-read) should NOT be included; these are in Field Service.

Meter Read Error Rate: Number of errors identified through the billing system before the bill is mailed, plus errors identified by the customer, as a % of total meter reads.

Meter Reading: Regular monthly Manual reads; AMR/mobile reads; AMI/Fixed network reads, primarily for billing purposes. Does not include check reads, re-reads, etc., which are included in Field Service.

Meter reading Window: Typically a meter is assigned to be read on a particular day, but if the meter reader misses the meter for some reason they usually have a 2-3 day window in which to gather the read.

Meter Shop: Typically employees who handle commercial or industrial meters and programmatic meter change outs.

Missed Read: A meter that is not read on the day that it is assigned (even if read within the read window).

MV-90: MV-90 is a solution for interval data collection, management and analysis and can be used as a data collection engine that interfaces to existing data management and analysis tools, or as an end-to-end interval data collection and management solution.

Multiple Commodity Bills: A bill for a single premise that reflects usage from meters for multiple commodities.

Normal Billings: Anything paid on-time is paid through normal billing. Anything paid late is considered part of credit process.

Occupancy (in Contact Center): The percentage of scheduled work time that employees are actually handling calls or in after call work mode. Does not include time waiting for calls. The % is often called the "occupancy rate".

Other Costs: Other miscellaneous costs not specifically broken out.

Outage/Interruption Reporting: Report an electrical outage, flickering lights, or an interruption to gas or water service.

Outsourcing: Outsourcing includes the complete turnover of the activity to a company third party company, so that the day-to-day activities are not controlled by the utility company. Outsourcing in utilities has grown from meter reading, outbound calling, and collection agencies to include call centers, billing operations, payment processing, and other activities.

Pay Bill: Allowing customers to use the contact center to pay bills.

Payment Agency, Payment Station: Agency is a manned facility owned and operated by someone other than the utility where a customer can pay a bill. Station is a kiosk or ATM-style machine where a customer can pay a bill without interactions with a person.

Payment Locations: including payment agencies, local offices, and pay stations.

Payment Posting Accuracy: Payments that have been posted accurately to the right accounts as a percent of all payments.

Payment Processing Clerk: Front-line worker who processes customer payments. Includes standard processing of ordinary payments, as well as investigating of payments which cannot be matched with a bill or an account.

Payment Processing Payments: Payments processed should roughly equal bills issued. Multiple checks for one bill are considered one payment. One check for multiple bills counts as multiple payments. Include all payments whether sent via mail, paid in local office, payment agency or pay station, paid on-line or through IVR or call center.

Pensions & Benefits Adder: The standard % that is used in internal calculations for labor overhead costs; Measured as a % of straight-time labor costs.

Percent Past Due 60 Days: Percent of bills unpaid at 60 days. Note for most utilities this is balance due at second bill.

Planned Estimate: Any estimate that is regularly scheduled such as billing monthly and reading bi-monthly.

Postage Costs: Cost of mailing bills and credit notices including prepaid envelopes if used for payment processing.

Pre-bill Audit: A pre-bill audit may result in "no error". So Errors found are a subset of the Pre-bill audit.

Productive Time: Walking between or driving between meters (moving within the route), reading meters are included in productive. Driving to the route is excluded from this measure.

Provide Meter Read: Use contact center to provide a meter read.

Remote Deposit: Remote deposit refers to the ability to deposit checks into a bank account from one's home or office without having to physically deliver the actual check to the bank. This is typically accomplished by scanning a digital image of a check onto a computer, then transmitting that image to the bank--a practice that became legal in the United States in 2004 when the Check Clearing for the 21st Century Act (or Check 21 Act) took effect. This service is typically used by businesses, though a remote deposit application for consumers has been developed. It should not be confused with: Direct deposit, which refers to the practice of posting an employee's weekly earnings directly to his or her bank account; Online deposit, which refers to a retail banking service allowing an authorized customer to record a check via a web application and have it posted, then mail in the physical check, giving the customer access to the funds before the check clears in the usual way.

Revenue Protection: activities vary greatly among utilities, depending on a number of factors, including commodities offered. The broadest definition includes both office and field activities surrounding revenue loss from theft, fraud, billing problems, and data tampering.

Rural: Fewer than 50 people per square mile.

Service Level (in Contact Center): defined as "x% of calls answered in Y seconds" See the Contact Center Section for how this is measured and variations e.g. with or without IVR.

Sign up for E-bill: Use contact center to sign up for electronic billing. Can be a call to rep or handled through IVR or internet.

Sign up for Other Services/Deregulation: Use contact center to sign up for additional services offered by the utility. Can be a call to rep or handled through IVR or internet.

Suburban: Between 50 and 500 people per square mile.

Summary Bills: A bill that shows the usage and amounts due for multiple locations and multiple meters.

Supervision Staff Categories: Only include Supervisors, Managers, or Directors who spend at least 50% of their time overseeing that function. Management who spend less than 50% of their time on a function should be excluded from the count. Someone spending 100% of their time overseeing both Meter Reading and Field Service would be counted as 0.5 FTEs in both areas.

Support Functions: Costs for FTEs or activities associated with either the whole CS function that cannot be allocated to another area of customer service or within a CS function that cannot be allocated to the activities described for that function. Only include people who don't spend at least 50% of their time in a specific functional area. This might include benchmarking, performance improvement, training and directors. Do not include corporate allocations, or any HR activities.

Technical support: includes people supporting work specific to that functional area. It refers to all tasks performed by an FTE in support of a Direct FTE. It is Mission oriented. It takes the form of a particular expertise or knowledge that can only be used for a particular activity or process. Trainers and schedulers are also part of this category. Technical support FTE will not work directly on a particular case other than assisting direct FTE resolve particular problems encountered. Their task may also be to analyze the process performance, produce new policies and design new business practices for direct FTEs in order to ensure the activity evolves towards greater performance.

Technology Costs: Any technology specifically used for this function such as meter reading devices, mobile data technology, telephone switch or call routing software, call monitoring software etc.

Transaction Fees (fees paid by utility): Fees for credit card transactions, bank charges, etc. Fees associated with payments (even if a call or a local office) still goes in payment. All third-party transaction costs associated with receiving and posting customer payments. This includes fees for lock box, credit card fees, and payment gateways.

Transactions: Transactions occurring between a customer and the company. Allocated into two types for volume count purposes: 1) Completable, where the customer conducts a transaction that triggers an event or a responding action by the company, such as a credit extension, payment, or request for service and 2) Convenience, where the customer gets information such as viewing a bill or usage history etc., but does not trigger a responding event by the company.

Turnover: Turnover is the percentage of annual staffing (turnover/total average staff over the year period) change in a given function due to employee departures, promotions, retirements, transfers to another department etc.. "Positive turnover" is turnover that is managed by the company and would include internal or directed transfers, promotions, or performance-related terminations. "Negative turnover" is turnover that is a result of an employee's decision and would include employee decided resignations, retirements, or self-motivated transfers to other departments.

Unable to Complete (UTC): Field situation where a field worker is unable to complete an issued service order. Reasons include: incorrect order issued, proper parts or tools not available, required pre-work or permitting not completed, was not able to get to the order due to schedule, time, backlog etc., or called-out for emergency/trouble.

Urban: Greater than 500 people per square mile.

Vehicle Costs: Costs associated with the operations & maintenance of vehicles for use solely by Customer service; usually charged out on a per mile or some other basis. Any payments for use of personal vehicles should also be included.

Vehicle Incident Rate: Only include statistics for company employees engaged in company work. Include all incidents taking place in company vehicle. Include incident taking place in contract or private vehicles when the driver is "at work". Do not include incidents occurring while commuting to work unless that time is paid work time or takes place in a company vehicle. Rate is per 1,000,000 miles.

Virtual Hold: Technology used in the contact center that allows a customer in queue to speak to a live agent the option of waiting in queue or receiving an outbound return call. How it works: Typically if there is an extended time to speak with a CSR, callers receives the option to stay on line or hang up and receive a return call in (usually) the same amount of time as if they stayed on hold. Before the completion of the call, customers provide or confirm the telephone number for the returned call and their name. Using recorded information, the virtual hold application service later dials the number, asks for the person who left the message, and connects the customer with the next available service representative.

Wage Rate: We are looking for the average hourly wage rate for the position, based on a fully-qualified incumbent.

Website Response Management: The group or person who determines the policy around handling web-initiated contacts including managing the group of people or the process of responding to contacts initiated at the web.

Write-offs Costs: Net percent of total revenue written off (e.g. less any recoveries). Goal is the actual number written off during the year, not necessarily what is in the FERC 904 account for the year, since that can be affected by changes in the provision for bad debt during the year (FERC 144 account). The annual “net” cost of bad debt. In other words any recoveries (less fees) should be subtracted from gross write-offs.

APPENDIX B: LIST OF DEMOGRAPHIC VARIABLES

A variety of demographic variables are helpful in understanding the performance of a distribution utility. The demographics of the electric systems have a substantial impact on the ability of the utilities to deliver low-cost, highly reliable service. At some point in the development of the longer-term, more comprehensive benchmark dataset for the CAMPUT members, a larger number of variables will be helpful in understanding the performance of each utility in its unique circumstance. Only a small set of variables is proposed initially, but a broader set could be added over time. The table below provides a listing of some of the variables that have an impact. Others might be added in the future as well.

Variable	Description
Number of customers	Number of customers served by the utility.
Customer density	Customers per square km and per km of line.
Asset value	Total investment over time in the assets of the utility. Most useful if separated between distribution lines, substations, and transmission lines
Overhead versus underground configuration	% of the distribution system installed underground and % overhead.
Km of line	Normalizing variable used to compare costs and reliability results versus the exposure
Tree density	Number of trees per sq km and per km of line that affect the service territory.
MWH transported (transmission)	Normalizer for use of system
MW of capacity	Normalizer for transmission system
MWH delivered (distribution)	Normalizer for distribution costs
MVA of capacity	Normalizer for substations, for costs and for asset utilization (% capacity used)
System peak loading for substations	Non-coincident peak across all substations
Degree-days experienced	Provides an indication of the severity of either high or low temperatures, with the resulting impact on energy usage
Prevailing weather patterns	Particularly of interest in terms of storm frequency and lightning stroke density, because of the impact on system reliability.
“Benchmark” wage rates – e.g. lineman, engineer	Provides a proxy for costs of labor in the local area, for use in making cost-of-living adjustments

APPENDIX C: BENCHMARKING IN NORTH AMERICA – UTILITIES PERSPECTIVE

This appendix expands on Section 4.1 of the main report, in which the benchmarking activities engaged in by utilities is introduced. The material in this appendix provides further examples and details of the specific activities the utilities participate in for their internal needs.

BROAD-BASED INDUSTRY STUDIES

Public Service Electric and Gas Company (PSE&G), the utility serving Newark, New Jersey and the surrounding area, has for many years performed a series of annual benchmark studies, with invited utility participants. There is an electric Distribution study, a gas Distribution study, and a Customer Service study. PSE&G originally started the studies for their own benefit, with the goal of being able to really track their own progress on the key areas they were interested in. The studies form much of the data for their internal performance management process, as well as giving them access to many contacts around the industry who they can share information with about emerging practices. About 30 utilities participate in each of the studies on a regular basis, benefiting from the fact that PSE&G funds the study.

Southern Company, the holding company for 4 major utilities in the Southeastern U.S., has performed a study of Electric Distribution for about 8 years, and has recently introduced a Transmission study, as well as a customer service study. The Distribution study has almost 50 participants each year, while the others are much smaller at this stage. The studies are focused on the needs of the Southern Companies for benchmarks and best practices, and the participating companies benefit from the fact that the Southern Company funds the entire effort.

The American Gas Association (AGA) and the Edison Electric Institute (EEI) have for about 12-15 years jointly run a study of Customer Service in gas and electric utilities. The study has the largest population of participating companies of any comparable study, with approximately 80 participants annually. This study covers all aspects of customer care with both metrics and practices.

The AGA also runs a series of best practices groups over a multi-year period. In Gas Distribution, for example, they perform an ongoing series of in-depth investigations into various aspects of gas distribution operations, rotating through the subjects on approximately a 5-year cycle. While the studies are focused on the gas industry, they also cover general-interest items such as fleet management and supply management, which are useful for combined electric and gas utilities.

ITOMS is the acronym for a group of very large-scale transmission operators who get together every two years for a detailed study of transmission operations. The focus is primarily on metrics, but with an understanding of the underlying system demographics as well. A few of the largest North American utilities are in this group, along with a few European, Asian, and African utilities.

CROSS-INDUSTRY STUDIES

These are studies in which utilities compare themselves to organizations in other industries where the industry isn't the driving factor for performance. In these cases, the specific business function is the key attraction for comparison. The primary reasons indicated for participation in these studies by utilities are the following:

- Keep current with the best emerging practices in the functional area
- Learn from other industries where that functional area might be closer to the "core business" of the other companies in the study
- Understand relative performance levels, primarily for setting targets
- Understand and/or diagnose strengths and weaknesses within the utility
- Help in determination of areas to outsource (or insource) where there is a mismatch of capabilities in-house versus those available outside of the utility

A few examples are provided below.

The Hackett Group has for about 20 years performed benchmark studies of the General & Administrative areas of businesses, first beginning in North America, and eventually growing to the point where today they cover companies all over the world. Their studies cover such areas as finance and accounting, legal, human resources, corporate services, support services, supply chain, and others. They gather data from hundreds of companies, and maintain a database which allows comparisons within industries and across industries. Many North

American utilities take advantage of these services on a regular basis, to better understand how their G&A functions rank against those of other companies and industries.

The Building Owners and Managers Association (BOMA) runs regular studies to summarize the costs and practices involved in operating and maintaining commercial buildings. Utilities participate in these to help assure they are achieving reasonable performance in the maintenance and operation of their office and operating facilities.

The International Fleet Management Benchmarking Association is a collection of companies who get together to perform benchmark studies of fleet management activities, practices, and performance levels. Membership is free for individuals, and companies can participate in the studies to study their performance and practices against those of other companies.

In the area of supply management, APICS is probably the best-known provider of comparative data, gathered through a variety of means from companies across many industries. Their studies are not tailored to the utility industry, but provide useful benchmarks of performance and costs for procurement, warehousing, logistics, and other aspects of supply management.

NICHE-FOCUSED STUDIES

Utilities participate in some very narrowly-focused studies for some very important functions. These studies range from small numbers to very large numbers of participants, but are concentrated on a narrow scope of activity. Below are two examples of such specific studies that utilities use to set performance benchmarks.

Vegetation Management: There are two different providers of focused benchmarking services in this area. These include CN Utility Consultants and ECI. Each runs periodic studies, with a large number of utility participants. CN has a larger proportion of Canadian representation in their studies than does ECI.

Customer Satisfaction: In the area of Customer Satisfaction, the J.D. Power study has taken a preeminent position over the past 5-10 years. It is possible for a utility to pay for a higher level of service, in which case J.D. Power will perform more in-depth research with that utility's customers.

Small Group Studies

Several small groups and associations run periodic or annual studies of different focus areas. Utilities participate as they find these study groups helpful in their own performance improvement processes. Two specific ones are introduced here.

EUCG, the Electric Utility Cost Group, has been performing studies each year for at least 15 years. The studies are managed by members of the consortium, and typically involve a questionnaire and a series of meetings of the participating companies. They include both metrics (outcomes) and practices, so that the participants can understand their relative position within the group, and learn about the current and emerging practices in the area under study. The focus of these studies is clearly on performance enhancement, not on uses for regulatory purposes. Fees are modest, since the group leaders volunteer their time, and involve essentially an annual member fee, rather than per-study charges.

EUBA, the Electric Utility Benchmarking Association, is another group of utility companies who regularly run studies of specific areas. Membership in this group is free, and there is a per-company charge to participate in any of the individual studies. Studies performed by this group cover many different subjects, and can be developed to fit the needs of a few or many utilities. As with EUCG studies, the areas are covered in terms of both performance outcomes and the underlying practices. Again, the companies participate in order to learn about better practices, with the goal in.

Outsourcing Contract Support

One way in which benchmarking is more and more frequently used is in support of outsourcing contracts for a variety of activities. In some cases, benchmark studies are used during contract negotiations, to set prices and service levels for various services. In other instances, particularly for long-term arrangements, the outsource contracts have a mechanism for updating the prices for the services over time. Some of those pricing mechanisms are built around benchmark studies for the specific services under study. These are most often found in large-scale outsource arrangements in which significant functions are outsourced to a major service provider. An example of such an arrangement is B.C. Hydro, who has outsourced most of their customer care activities to Accenture. The contract has a provision for a benchmark study to be commissioned every two to three years, and the pricing under the contract is set up to be tied to the outcomes of the study. That guarantees the long-term contract to Accenture, while at the same time providing a long-term fair market price to B.C. Hydro.

APPENDIX D: BENCHMARKING IN OTHER JURISDICTIONS – OFGEM PAS 55 REQUIREMENTS

The Table of Contents outlined how OFGEM uses PAS 55 Requirements is included in the Table below.

Table D1: PAS 55 Reporting Requirements

An excerpt of the relevant section of the reporting requirements includes: *4.1 General requirements* *4.2 Asset Management policy* *4.3.1 Asset Management strategy* *4.3.2 Asset Management objectives* *4.3.3 Asset Management plan(s)* *4.3.4 Contingency planning* *4.4.1 Structure, authority and responsibilities* *4.4.2 Outsourcing of Asset Management activities* *4.4.3 Training, awareness and competence* *4.4.4 Communication, participation and consultation* *4.4.5 Asset Management System documentation* *4.4.6 Information management* *4.4.7.1 Risk management process(es)* *4.4.7.2 Risk management methodology* *4.4.7.3 Risk identification and assessment* *4.4.7.4 Use and maintenance of asset risk management* *4.4.8 Legal and other requirements* *4.4.9 Management of change* *4.5.1 Life-cycle activities* *4.5.2 Tools, facilities and equipment* *4.6.1 Performance and condition monitoring* *4.6.2 Investigation of asset-related failures, incidents and nonconformities* *4.6.3 Evaluation of compliance* *4.6.4 Audit* *4.6.5.1 Corrective and Preventative action* *4.6.5.2 Continual Improvement* *4.6.6 Records* *4.7 Management review*

APPENDIX E: OVERVIEW OF DATA CURRENTLY COLLECTED BY REGULATORS IN CANADA

This report is available upon request, through CAMPUT.

APPENDIX F: CAMPUT MEMBERS INTERVIEW NOTES

Over the course of the project, interviews were conducted with utilities and regulators across Canada, the United States, the United Kingdom and Australia. A list of organizations contacted was provided to CAMPUT. Although the insights from these interviews was used to formulate content and recommendations for this report, no details from any of the interviews were shared in anything other than the aggregate format.

APPENDIX G: EXISTING STANDARDS

Although some of these specific metrics are not being recommended for CAMPUT, they are included to demonstrate how metrics are being used in other applications.

CUSTOMER SERVICE STANDARDS

OBJECTIVE MEASURES

Customer service performance is typically broken down into major functions, including contact centers, billing operations, meter reading, field service. While there are no official "standards" that are universally accepted, there are a number of metrics that almost all companies track for their internal use in managing their businesses.

The most-measured function among these is contact centers, with many metrics used by the utilities to track, monitor, and manage performance. Key ones that are used by most utilities include the following:

- Service Level, defined as the % of calls answered within x seconds.
- Average Speed of Answer (ASA)
- % of calls Abandoned

In all of these areas, there are differences in the tracking and reporting methods used by different utilities. In the case of service levels, the x value ranges from 20 to 30 to 60 seconds, with 30 being most frequently-used, but certainly not universal. Further, the question of when the time begins varies based on whether or not an Interactive Voice Response (IVR) unit is used, and a choice as to measuring from the time the customer opts out of the IVR or from the time the customer enters the IVR. Finally, for this metric, the calculation varies depending on whether or not all calls are considered in the denominator or if the abandoned calls are excluded.

Similarly for the ASA and the % abandoned, there are calculation differences between companies, so while the metrics are "standard", the measurement techniques aren't. In this highly measured area, it is possible for most companies to measure and report results in the same way, because of the equipment used for measurement. With the proper motivations, it would be possible to create a "standard" means of measuring these three statistics and get useful benchmark results.

For Billing, Meter Reading, and Field Service, the most frequently-used measures of performance are Bill Accuracy, Meter Read Accuracy, and % of appointments kept respectively. Unfortunately, these suffer the same problems as the Call Center metrics, in that there are no fully-agreed ways to measure them, and no "official" body sets a proposed method for measuring them.

The American Gas Association and Edison Electric Institute run a joint study annually in which they capture all of the above metrics for Customer Service functions, from about 80 Canadian and U.S. utilities. Within that study, they suggest methods for measuring all the items listed above, but there is no strong method of validating that the participating utilities do in fact measure in the suggested ways.

CUSTOMER SATISFACTION STANDARDS

Customer satisfaction is a critical issue for most utilities and for their regulators. Measurements abound for what is considered customer satisfaction. While almost every utility has its own set of metrics and methods of measuring customer satisfaction, and those methods are rooted in valid statistical techniques, there is no one technique that can be identified as a "standard" for the industry. Some companies focus on customers with recent contact with the utility, others use a random sample of all customers. Some use telephone surveys, others use written or electronic means of collecting opinions. The areas of focus also vary, with companies concentrating on company image, price, service levels, customer perceptions of value, and many other possible elements.

The closest thing to a "standard" measurement of satisfaction for utilities in North America is the J.D. Power satisfaction measurement approach. This is one in which J.D. Power defined a method for measuring satisfaction, and began applying that across the North American industry. Over a number of years, their measures of satisfaction, combined with their reporting and marketing of the results, have become accepted in some parts of the industry. Companies who purchase their reports often indicate privately that their own measurement approaches and analysis techniques are more robust and create higher value in terms of their ability to use the results to improve their service to customers. However, the J.D. Power results are comparable across companies, and have the weight that comes with substantial marketing of the results by J.D. Power themselves. The challenges with this study are included to explain why a similar metric is not being proposed for CAMPUT.

Standards of customer service tend to fall into two categories: objective service levels as measured by specified metrics, and customer complaints as measured either by complaints to a regulator, or complaints directly to the utility.

APPENDIX H: FORM 1

The FERC Form 1 is a report that major investor-owned utilities in the U.S. are required to submit to FERC on an annual basis. The Form requires accounting data, collected and reported according to the FERC Uniform System of Accounts. It also requires a variety of other operational and statistical data. The information is reported to FERC and made public, so that any company's report can be downloaded from the FERC website.

For an example of the FERC Form 1 as submitted by utilities in the U.S., please visit the FERC website using the link below:

http://elibrary.ferc.gov/idmws/search/results.asp

Our report reviewed the material submitted by Nstar, the utility serving Boston, Massachusetts and the surrounding area. There is nothing significant about having chosen the Form submitted by Nstar, it simply reflects the fact that one was needed as an example for this report.

APPENDIX I: AUSTRALIAN FILING REQUIREMENTS

An issues paper from the Australian Energy Regulator (AER) entitled: Electricity Distribution Network Service Providers Annual Information Reporting Requirements, August 2008 was used to help identify what is currently collected by regulators in Australia.

For a copy of this report, please visit the AER website by using the link below:

http://www.aer.gov.au/content/index.phtml/itemId/721366

APPENDIX J: U.K. FILING REQUIREMENTS

The U.K. has extensive filing requirements for the distribution companies and for National Grid. The cost elements alone are comprehensive, and required for each year of each 5-year price review period. Utilities are provided with a set of instructions for costs to be filed by each distribution utility. They are also given a set of the standard filing requirements for National Grid on the transmission side. The National Grid document is a spreadsheet, and therefore the formatting is somewhat awkward in this report. The most relevant report reviewed was entitled:

Electricity Distribution Price Control Review Price control cost reporting Rules: Instructions and Guidance Dated April 2009

For a copy of this report, please visit the OFGEM website by using the link below:

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Cost%20Reporting%20R

APPENDIX K: HYDRO ONE BENCHMARKING REPORT: EXECUTIVE SUMMARY

The following material constitutes the Executive Summary from a benchmark report prepared for Hydro One by PA Consulting. The entire report was filed as part of the 2008 rate case filing by Hydro One, and has become part of the public record as a consequence of having been filed in that rate case. Its inclusion here is intended to provide an example of the ways in which utilities have used benchmarks in support of rates and regulatory proceedings.

EXECUTIVE SUMMARY

Hydro One commissioned execution of a high-level Distribution benchmarking study, with the purpose of understanding its relative position among a group of "peer" utilities across a range of cost, reliability, and safety metrics. PA Consulting Group has performed that study, with the attached report as the result. We briefly outline below the approach taken to the study, the types of results found, and some steps to be taken in the future.

BACKGROUND AND STUDY OBJECTIVES

Hydro One was asked by the Ontario Energy Board to perform a high-level benchmarking study in support of revenue requirements in a rates proceeding. That request came as part of the decision published April 12, 2006 by the OEB in response to Hydro One's Distribution Rates Application and was reinforced in the recent decision on Hydro One's Transmission Application. Hydro One took the opportunity to perform the study to meet the directive of the OEB, while at the same time investigating two specific areas within its distribution operations (vegetation management and meter reading) that may offer improvement opportunities.

APPROACH

The approach followed a direct series of steps designed to identify an appropriate peer panel of utilities for comparison while simultaneously selecting a group of performance measures for tracking the performance of the companies. These steps were followed by data collection from the selected peer group of companies, and summary and analysis of the resulting data. The summary consisted of development of charts and graphs showing the outcomes for the performance measures, and then review of what those results say about the performance of Hydro One.

A key element of the approach to the project was in selecting the appropriate metrics for tracking success in a distribution company characterized by a very low density service territory. A low density territory requires substantial amounts of electric system assets to serve each customer, and therefore the appropriate performance metrics are required to address that fact of the electric system. Measures based on, or normalized by, the length of distribution lines are appropriate for a company like Hydro One.

FINDINGS AND CONCLUSIONS

The overall results of the benchmark comparisons are the following:

COST

When compared on a per-km of line basis, Hydro One's costs are in line with the norm of the group, and in some cases even leading. Their costs are higher than average for the comparison panel when measured on a per-customer basis. Where capital spending is concerned, particularly with respect to per-km metrics, the costs are below the mean for the group.

ASSET REPLACEMENT RATE

Hydro One's asset replacement rate is low in comparison to the group. This is measured in terms of the amount of capital spending in relationship to the existing asset base. A very low value for the long term could indicate underinvestment in the electric system.

RELIABILITY

When the reliability figures are normalized for the km of line, Hydro One's performance is in line with the norms of the group. Hydro One has comparatively poor reliability within the panel group, when measured by metrics such as SAIDI and SAIFI.

Safety

Safety performance for Hydro One is overall about average for the group of utilities who reported data for the study, but the results are mixed. When reviewing recordable incidents, Hydro One falls above (worse than) the average performance for the panel of companies. On the lost-time incident rate, Hydro One is significantly better than the average of the group.

Meter Reading

Meter reading costs for Hydro One are relatively low compared to the panel, when normalized by distance. When viewed on a per-customer or per-read basis, the costs are very high. This is reasonably explained by the very low density of the territory, which leads to long distances, either walking or driving, between meters for reading.

Tree Trimming

For vegetation management, the Hydro One costs are higher than the average for the comparison panel. The service territory demographics (e.g. size and density of territory, vegetation coverage, electric system configuration) substantially influence the performance results for this area.

Summary

The study has produced some useful results for the company. In particular, the results provide an accurate portrayal of the performance of the company, while at the same time demonstrating the importance of measuring and reporting performance in an appropriate manner to fit the individual situation for each utility. Hydro One's service territory has some unique characteristics, most notably its low density, and the performance of the company appears different depending on whether or not those characteristics are taken into account in measuring performance. Overall performance of the company rates as "good to very good" when performance is normalized by the volume of assets (e.g. km of line). However, when measures that are normalized by customer base (e.g. spending or customer hours per customer served) are used, Hydro One performance appears to be less efficient. The low density/rural nature of the Hydro One system leads to this, since customer-normalized metrics tend to favor higher density systems.

In using the results of this (or any other benchmarking study), it is important to understand both the benefits and limitations of the work. This is a high-level study, and it is important to take care in analyzing and applying the results, assuring a substantial degree of understanding of the underlying data and analysis.