UNDERTAKING

Undertaking

PROVIDE FURTHER PRODUCTIVITY STUDIES OR BENCHMARK STUDIES, IF ANY AVAILABLE

Response

See attached Asset Management Performance Benchmarking by CIGRE.

Hydro One also purchased the 2006 Annual Service Continuity Report on Distribution System Performance in Electrical Utilities by Canadian Electricity Association, which provide aggregate distribution system performance data. This report is available for purchase at the CEA web site http://www.canelect.ca/en/home.html

SC C1

System Development and Economics

Working Group C1.11

Asset Management Performance Benchmarking

Technical Brochure – June 2008

Asset Management Performance Benchmarking

Working Group C1-11
SC C1 System Development and Economics

June 2008

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Overview and Organization of Technical Brochure

Working Group C1.11
Asset Management Performance Benchmarking

This Technical Brochure on ***Asset Management Performance Benchmarking*** provides the results of a study on the current state of performance measurement and benchmarking, within the High Voltage Electricity Utility Industry, conducted by CIGRE Working Group C1-11 (**Study Committee C1 System Development and Economics)**. These results are based on a world-wide survey of the performance measures utilized by 19 large electricity utilities and a global industry literature search of publications related to Transmission System Reliability Measures, which are utilized or recommended for use by Electricity Industry or Regulatory Associations. The body of work emphasized Transmission System Reliability Measures, as practiced by selected electricity utilities or recommended by various Electricity Utility or Regulatory Associations. The study also includes analyses and observations on emerging issues related to the use of such Measures and the associated impact on Performance Benchmarking for improving utility performance or having regulatory implications.

The Technical Brochure includes a summary and detailed compilation of Corporate Performance Measures utilized by 19 large electricity utilities around the world; summarizes key findings, conclusions and recommendations regarding the application of Transmission System Reliability Measures from the survey of the 19 utilities and from reports prepared by Electricity Industry and Regulatory Associations on this subject. The Technical Brochure also identifies the typical challenges related to Benchmarking Transmission System Reliability Performance and includes a list of generally accepted factors which could impact transmission system reliability performance and should be considered when conducting either intra-utility or inter-utility reliability comparisons. Based on a review of recent industry literature, the Technical Brochure also identifies the approach most commonly used by utilities and regulatory authorities to establish a base-line of transmission system reliability performance, given the challenges of inter-utility comparisons.

The Technical Brochure does not provide specific recommendations for Corporate Level Performance Measures or Transmission System Reliability Measures, which should be adopted by the electricity utility industry. Measures which are adopted for the management of these businesses are dependant on a number of utility specific factors such as the availability of historic performance information, local standards, regulatory compliance requirements, the return requirements of the shareholder, the business objectives and risk tolerance of the Utility Leadership Team, historic reliability performance, the technical or commercial boundary between the transmission system and customers and a range of other factors. CIGRE Technical Brochure 261 dated October 2004 provides excellent guidance on establishing an overall Reliability measurement philosophy and recommends indices based on the philosophy selected. This work remains current and provides a basis for the study undertaken by Working Group C1.11. Given the Terms of Reference for Working Group C1.11, the study investigated the degree to which the various reliability measures recommended by Technical Bulletin 261 have been adopted and related the findings to the implications on electricity utility Performance Benchmarking.

At the request of the 19 Electricity Utilities participating in the study, the Technical Brochure is designed to maintain the confidentiality of the participating utilities. This will preclude inter-utility comparisons of the measures selected, which are a function of the unique business circumstances faced by each of the participating utilities.

This Technical Brochure is organized in three major sections:

The first section provides an ***Executive Summary*** of this subject area which highlights the major findings and conclusions of the study and related industry literature review.

The second section provides the ***Detailed Study*** results, including a description of the approach used to conduct the study, analysis of the survey results and literature review along with the development of detailed conclusions regarding the Corporate Performance Measures, Reliability Measures and implications on Performance Benchmarking. The Study section of the report is separated into two sub-sections. The first sub-section discusses the Corporate Performance Measures portion of the Study, where the survey information for the 19 participating utilities is reviewed and conclusions developed. The second sub-section provides the findings and conclusions associated with the more detailed review of Reliability Measures and Benchmarking. In this latter sub-section industry and regulatory issues are identified, based on a literature review of this subject area, and these are discussed in conjunction with the Reliability related findings from the first sub-section on Corporate Performance Measures.

The third section is comprised of the ***Appendices*** where the detailed background materials are provided. Areas of key interest to utilities may include the Compilation of Survey Responses in Appendix B, the Utility Specific Measurement Profiles in Appendix C and the detailed Outline of Measure Definitions in Appendix D. These appendices allow for additional detailed analysis of the survey results and provide a good reference of the types of detailed measures used by the 19 participating electricity utilities. This detailed information may be of benefit to utilities reviewing their existing performance measures or considering the implementation of new measures.

1. Executive Summary

1.1 Study Overview

The main objective of the Working Group (WG) was to develop a broad understanding of the types of Corporate Performance Metrics (CPM) currently being used across the electricity utility industry, with a more detailed focus on system level reliability metrics and related benchmarking considerations and challenges. In accordance with the approved Terms of Reference the intent of the review was twofold:

1. Establish from a corporate level perspective the metrics currently in place and identify those which are important to participating utilities across the world.

2. Establish an information source related to metrics used for measuring system level reliability and other performance and cost metrics as determined appropriate.

This inventory of corporate level performance measures will provide the industry with an overview of those measures currently used by various utilities to monitor and manage the performance of the business, in the most critical areas.

Through the guidance provided by the Study Committee and Working Group members the information was also assessed to investigate correlation between the measures utilized and the function of the utility within the local electricity market (Transmission System Owner - TSO, TSO and System Operator, Vertically Integrated Utility) and the ownership structure (Public - government or Private).

A total of 19 utilities agreed to participate in the study providing a good overall cross section of utility characteristics, functions and ownership arrangements.

The following utilities participated in the study:

Utility	Country	Utility	Country
Continuon	Netherlands (NL)	Altalink	Canada (CA)
British Columbia Transmission Company (BCTC)	Canada (CA)	Delta Electricity	Australia (AU)
American Electric Power (AEP)	United States of America (US)	Eskom	South Africa (ZA)
Great Lakes Power	Canada (CA)	Hydro Quebec	Canada (CA)
Korean Electric Power Company (KEPCO)	Korea (KR)	National Grid	England (GB)
Gestionnaire Réseau de Transport d'Electricité (RTE)	France (FR)	Manitoba Hydro	Canada (CA)
Newfoundland & Labrador Hydro	Canada (CA)	Nordostschweizerische Kraftwerke AG (NOK)	Switzerland (CH)
Transgrid	Australia (AU)	TenneT	Netherlands (NL)
Energie Baden-Wurttemberg (EnBW)	Germany (DE)	Transba	Argentina (AR)
Hydro One	Canada (CA)		

1.2 Corporate Performance Measures Study

Based on the business objectives of companies responsible for delivering high voltage electricity transmission services and the survey results, the corporate performance measures were categorized into the following 5 key business performance areas:

- **Finance / Business**
- **Safety**
- **Reliability**
- **Customer**
- **Employee**

The most common performance measures under each category and the extent of utilization are summarized in the following Table:

Performance Measure Areas	Most Common Measure (Note – More than one measure appears if equal utilization)	Most Common Measure Utilization (Percent Of Responding Companies Utilizing Measure)
Finance/Business	Net Income After Tax	26%
Safety	Serious Lost Time Injuries	37%
Reliability	System Average Interruption Duration Index (SAIDI) & Unsupplied Energy (UE)	47%
Customer	Customer Satisfaction Survey of Transmission Load Customers; Transmission Generation Customers & Commercial Customers	16%
Employee	Employee Engagement Index (Based on Alignment, Capability, Resources and Motivation)	11%

Key Observations by Measure Area

The following key observations were made from a review of the compilation of results, appearing in Appendix B:

The **Finance / Business** measures were highly varied with "Net Income", both before and after taxes, being found to be the most common. "Credit rating" was also used and a range of financial tools such as "cash flow" are being applied. The key Business or operational measures included project monitoring procedures to ensure accomplishment of work programs. The most popular number of measures utilized for monitoring and managing this business area at the corporate level was 2.

In the area of public and employee **Safety** the measures primarily focus on the frequency and severity or seriousness of injuries. The range of measures used is designed to capture the various rates of injuries, with emphasis on serious outcomes. A significant finding in this area was that the majority of the responding utilities do not use the measures established by the Occupational Safety and Health Administration (OSHA), which is based on measuring injuries for 200,000 hours worked, or the International Union of Producers and Distributors of Electrical Energy (UNIPEDE), which is based on measuring injuries for 1,000,000 hours worked. It was also noted that some utilities used measures to report on the managing of the safety processes. The most popular number of measures utilized for monitoring and managing this business area at the corporate level was 3.

The **Reliability** measures used primarily focus on the two key points of frequency and duration of outages. A significant number of “unsupplied energy” and “unavailability” measures are also present. These measures were sometimes supplemented by specific or specialized measures, such as planned and unplanned availability of specific equipment types (i.e.; lines and transformers) to facilitate root cause analysis for the purpose of performance improvement. The most popular number of measures utilized for monitoring and managing this business area at the corporate level was 3.

While a number of **Customer** measures are listed they tend to be variations on customer surveys. However, there appears to be an emerging trend towards using surveys which are segmented by customer groups rather than general surveys. The results also indicate that utilities are monitoring the implementation of survey comments by tracking specific initiatives designed to respond to customer concerns and thereby improve customer satisfaction. The most popular number of measures utilized for monitoring and managing this business area at the corporate level was 2.

The **Employee** measures are more varied than the other measures but generally focus on employee surveys / satisfaction, with equity issues, and planning for the future through the use of training measures also being utilized. The most popular number of measures utilized for monitoring and managing this business area at the corporate level was 1.

Effect of Utility Market Function or Ownership Structure on Use of Performance Measures

The C1 Study Committee members and Working Group members indicated that if possible, the study should investigate if there is any correlation between the types of performance measures used and the function of the utility within the local electricity market or the ownership structure of the utility.

In terms of utility function within the local electricity market the 19 participating utilities could be classified as follows:

1. Twelve of the 19 participating utilities were classified as Transmission System Owners, with responsibility for maintaining, replacing and expanding the asset base.

2. Four of the participating utilities were classified as Transmission System Owner / Operators, having responsibility for operating the local electricity system, along with the ownership role.

3. Three of the participating utilities were classified as Integrated Utility Owners with responsibility for Generation as well as Transmission.

The only common factor which could be identified when reviewing the information in accordance with this structural arrangement was that all the utilities falling under the second classification (System owner / operators, with additional responsibility for operating the local electricity system, along with the ownership role) utilize the **Unsupplied Energy** measure for Transmission system reliability.

Of the 19 utilities participating in the study 12 are publicly (government) owned and 7 are privately owned enterprises. There were no discernible differences in the performance measures utilized by publicly owned versus privately owned companies. This may be a result of the fact that today many publicly owned companies are expected to operate as private commercial enterprises. Typically the executive and management teams of these companies are selected on the basis of business acumen and are expected to operate the companies on a fully commercial basis.

Summary of Conclusions – Corporate Performance Measures Study

This work provides the industry with a good sample of performance metrics utilized by nineteen utilities across the world, which are operating under a variety of electricity market structures, regulatory regimes and ownership structures.

The survey information shows that there are a wide variety of measures utilized in managing utilities having responsibility for delivering Transmission services to customers.

A detailed review of the survey information indicates that many of the measures, which are related to a similar business area, have different detailed attributes, interpretation details and data collection requirements.

Performance measures are typically implemented within a company to measure the success in meeting the key strategic objectives of the company. These strategic objectives are established and monitored by the Board of Directors and Leadership Team of the company and are typically a function of the return requirements of the Shareholders, risk tolerance of the Leadership Team, historical performance of the business, degree of customer satisfaction and compliance requirements of local regulatory authorities. The variability in the utility specific strategic objectives (and the fact that management judgement must be applied in establishing the related performance measures) likely accounts for the wide disparity of performance measures used, even though the utilities are all operating the same technical business.

The wide disparity of performance measures currently in place within the electricity utility industry and the related disparity in interpretation details and data collection requirements make accurate benchmarking an extremely challenging endeavour.

Benchmarking is primarily used by utilities for the purpose of identifying "best practices", for improving operational and / or cost performance. When benchmarking is used for this purpose, a significant degree of detailed discussions and professional judgement can be utilized by the specialized experts, to ensure proper interpretation and application within a specific business area.

When benchmarking is used for Regulatory purposes (for conducting effectiveness and efficiency comparisons between different companies) with potential for compliance related financial penalties and incentives, much more careful analysis and investigations are required, given the implications on the affected companies, their customers and shareholders.

1.3 Reliability Measures & Benchmarking / Industry Information Sources

In response to the objective of **establishing an information source related to metrics used for measuring system level reliability** the study includes a review of background CIGRE literature in this subject area along with a review of recent industry or regulatory based publications related to transmission business reliability measures and benchmarking.

The background review uncovered **CIGRE Joint Working Group (JWG) Report C4.07 / CIRED, entitled POWER QUALITY INDICES AND OBJECTIVES,** dated January 2004 / revised March 2004. This work was later published as **CIGRE Technical Brochure 261 dated October 2004**. This 2004 background report provides power quality data (including data on continuity of supply or system reliability) gathered from several different countries across a number of monitoring points over a number of years. The report provides guidance on the key factors that need to be considered when gathering and presenting data. In so doing the report considers the benefits of consistency but recognizes the inherent differences between different electrical systems and different power quality objectives. The report develops the case for a consistent set of power quality indices and objectives that can be seen as the outer envelope of performance for each power quality parameter. The report also provides comments on Benchmarking and Comparative Reporting.

The review of recent industry literature concentrated on identifying industry based documentation on Transmission Reliability Performance Measures, issued since the above mentioned work of **CIGRE JWG C4.07 / CIRED (Technical Brochure 261)**.

Also included is an assessment of the degree of application of recommended reliability measures provided within the CIGRE JWG C4.07 / CIRED Report, by either the broad range of utilities participating in this study or found in any other industry surveys / publications, conducted since the 2004 CIGRE JWG C4.07 / CIRED Report (Technical Brochure 261).

The industry literature review uncovered the following key documents related to transmission business reliability measures and benchmarking, which were issued since the work of **CIGRE JWG C4.07 / CIRED,** was published:

- **Electrical Power Research Institute (EPRI) - Transmission Reliability Impact Metrics Project; Final Report is dated September 25, 2007.**

The report summarizes technical recommendations from a team of transmission owner representatives (in North America) to improve transmission reliability performance assessment. The scope of this project included the long term, retrospective performance assessment of transmission reliability impacts due to transmission owner actions and facilities. The report recommendations are primarily intended for use in strategic planning applications and also for guidance in transmission regulatory policy development currently in progress.

The group selected methods and metrics on their ability to meet requirements for: comparability, simplicity, relevance, and attainability.

Previous EPRI study report recommendations included transmission facility availability metric recommendations for Deliverability and Delivery. This project augmented that work with impact metrics which quantify the significance of facility unavailability in terms of the overall functional objectives of interconnected transmission operations: interconnection integrity; transmission customer service continuity; and wholesale market function. The integration of these performance dimensions (availability and impact) is necessary because transmission owners need to know how facilities and actions, within their responsibility, significantly impact performance.

The EPRI Transmission Reliability Impact Metrics Project – Final Report dated September 25, 2007 was developed for Participant Distribution only. The report can be obtained from EPRI by contacting Mr. Ram Adapa at EPRI at following e-mail address: RADAPA@epri.com

Since this is not a publicly available report key findings, conclusions and recommendations are not outlined within this study. It is recommended that any utility interested in the subject area obtain a copy of this important report since it represents an excellent research reference for establishing reliability performance measures.

- **Council of European Energy Regulators (CEER) - Third Benchmarking Report on Quality of Electricity Supply 2005**

This Third Benchmarking Report on Quality of Electricity Supply by CEER is a publicly available document on the CEER – Web site.

Chapter 1 of this report deals with Continuity of Supply and outlines the various reliability measures utilized in 20 countries covered by this version of the CEER report. The report also identifies actual available performance levels, standards and the incentives used in service quality regulation within Europe.

The analysis determined that the most common indicators used for Transmission were found to be:

- **Energy Not Supplied (ENS)**
- **Average Interruption Time (AIT)**
- **System Average Interruption Duration Index (SAIDI) at the transmission level**
- **System Average Interruption Frequency Index (SAIFI) at the transmission level.**

The main conclusions of the report include the following:

- Both the number and duration of unplanned outages are showing downward trends in most European countries.
- Excluding exceptional events from the unplanned performance figures highlights that significant improvements are being made in many European countries for both the duration and number of interruptions.
- Countries with good relative performance in the areas of frequency and duration of interruptions have been able to make further improvements.
- Short interruptions have generally not been rising despite a move toward automation and remote control techniques, as cost saving measures.

In relation to benchmarking the report indicates that "Different approaches to continuity of supply regulation, and in particular the different continuity indicators and standards adopted, recording methodologies used, combined with different geographical, meteorological and network characteristics, makes benchmarking of actual levels of continuity of supply difficult."

The report identifies several reasons for the expected differences in the reliability performance of specific utilities and the related challenges this represents to performing accurate benchmarking. The findings of the CEER Report are consistent with the findings of Working Group C1.11.

- **Canadian Electricity Association (CEA) Reliability Recommendations and Policies**

Development and monitoring of Reliability measures for Transmission Systems at Delivery Points is carried out within the CEA under the Electric Power System Reliability Assessment / Bulk Electricity System (EPSRA / BES) program.

Metrics proposed by the CEA - Consultative Committee on Outage Statistics (CCOS) and accepted by the CEA Transmission-Council recommended for use in a potential regulatory setting include:

Transmission System Average Interruption Frequency Index (T- SAIFI)
Transmission System Average Interruption Duration Index (T-SAIDI)

Each of these indices must be assessed annually, using forced, sustained events, to establish the Canada participant average.

Definitions for these measures are as follows:

Transmission System Average Interruption Frequency Index - Sustained Interruptions (T-SAIFI-SI)

A measure of the average number of sustained interruptions that a DP experiences during a given period, usually one year.

$$\text{T-SAIFI-SI} = \frac{\text{Total No. of Sustained Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

Transmission System Average Interruption Duration Index (T-SAIDI)

A measure of the average total interruption duration that a DP experiences during a given period, usually one year.

$$\text{T-SAIDI} = \frac{\text{Total Duration of all Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

Note: For the purpose of the above T-SAIFI index, Sustained Interruptions are defined as interruptions which are one minute or longer in duration.

Recommendations for the use of more detailed metrics (further granularity of T-SAIFI and T-SAIDI) by the CEA - CCOS to the CEA Transmission Council are pending.

As a result of the interest in benchmarking of Transmission and Distribution systems by Regulatory Authorities in many Canadian provinces, the CEA has found it necessary to develop and issue a policy statement on the use of Benchmarking Data in Regulatory Settings. This policy statement is dated June 5, 2006 and is directed at Canadian electricity industry stakeholders. The policy statement is attached as Appendix E and is available on the following web-link:

https://www3.eub.gov.ab.ca/eub/dds/iar_query/ShowAttachment.aspx?DOCNUM=667215.

Some of the primary elements of the policy statements are summarized below:

- Electricity utilities have been utilizing benchmarking for a number of years to improve operational performance, by establishing utility best practices, in a number of key business areas (continuity of service, customer satisfaction, employee safety and cost related indicators). Utilities typically perform such analysis on a confidential basis and before any information is utilized to improve business processes applicability is assessed and subject to significant degree of professional judgement. Attempts by Regulatory Authorities to use any related information for other purposes, such as peer-to-peer comparisons, is likely to result in incorrect results and may inhibit the important inter-utility efforts of benchmarking for the purposes of operational improvement.

- Before utilizing benchmarking information in regulatory settings an appropriate framework must be established with proper consideration of caveats, standardized interpretations and collection methodologies.

- Peer-to-peer comparisons, especially for establishing pass / fail criteria for compliance (breach and consequence) purposes is not recommended due to the complexity of identifying true “peers”. The complexity is related to significant inter-utility differences which affect many performance measures, including reliability. This includes the geography and climate within which the system must operate; historic system design; system age; degree of interconnection; degree of automation and a range of other factors.

- Trending a utilities own performance over time should be used as opposed to single year comparisons between utilities.

- The CEA will work in cooperation with regulatory authorities to ensure indicators that are used in regulatory settings are accurate, verifiable and verified for use in assessing individual company performance over time.

- **CIGRE 2006 Paper C5-109; Power Transmission Performance Indices**

This paper proposes standardized definitions, data compilation and calculation methodologies and reporting methods which, at the time of publication, were being adopted by some of the Power Transmission Authorities / Companies in the Gulf Cooperation Council Region.

The supply reliability indices proposed are as follows:

- **System-Minutes Lost Index**

- **System Average Interruption Frequency Index**

- **System Average Interruption Duration Index**

- **System Average Restoration Index**

These performance measures / indices were selected based on their recognition by standards authorities and other electric utilities and on their relative simplicity in compilation / calculation. The paper indicates that these indices "present quantified values from which the performance of a power system can be realistically and objectively measured and evaluated as well as highlighting potential areas where improvement is needed". The paper also provides guidance on the use of related equipment reliability indices, which facilitate root cause analysis to "target weak areas and launch improvement plans".

Section 6.0 of the paper covers Analysis and Benchmarking, where the paper cautions that:

- Differences in index values between areas or systems do not necessarily represent differences in the effectiveness of the company, since these differences can be considered as normal and expected due to the different equipment types installed, the system voltage ranges utilized, different operating environments and philosophies adopted over the course of the history of the utility.

- It is more meaningful to look at the long term trend of specific performance measures rather than at figures for an individual reporting period, due to the possible occurrence of rare or abnormal incidents in a particular reporting period.

- The method of reporting or recording disturbance data by a specific utility could affect the values of indices calculated and therefore the comparability between utilities.

- The performance indices of each power system should be evaluated on their own merits and only “apples versus apples” comparisons are valid.

Comparison of CIGRE Joint Working Group C4.07 / CIRED Recommended Transmission Reliability Measures with Actual Utility Practices

A review of the reported reliability measures, associated with the participating utilities within this study, and the CEER - Third Benchmarking Report on Quality of Electricity Supply 2005, indicates that the recommendations of **CIGRE JWG C4.07 / CIRED** are beginning to have an effect on influencing the transmission system reliability measures utilized by the electricity utility industry.

Acknowledged Challenges in Inter-Utility Benchmarking for Transmission Reliability Performance

A review of the recent industry publications indicates a general acceptance that inter-utility benchmarking of reliability performance measures is very difficult, due to the following key factors:

- Historic use of different supply continuity indicators
- Variations in recording methodologies
- Differences in supply standards
- Variations in environmental (geographical and meteorological) factors
- Differences in network characteristics

This general acceptance is found to exist both within electricity utility industry publications and publications associated with related regulatory authorities.

Generally Accepted Practices for Establishing a Baseline of Transmission Reliability Performance

The literature review has identified that the most common industry practice for establishing a baseline of Transmission Reliability Performance consists of identifying one or more generally accepted reliability measures and establishing the historical level of performance based on best available information. Most utilities and regulatory authorities expect the historical level to either be maintained or incrementally improved depending on the extent and pace of system expansion and refurbishment / replacement plans. They also expect the development of valid comparisons over time as a method for rationalizing the need for possible further improvements.

Effect of Utility Market Function or Ownership Structure on Reliability Performance Measures

As mentioned in the above summary for the Corporate Performance measures section, the only common factor which could be identified when reviewing the information in accordance with the typical structural arrangements was that all participating utilities having responsibility for both owning and operating the local electricity system, utilize the **Unsupplied Energy** measure for Transmission system reliability.

The ownership arrangement (public or private) had no discernible effect on the reliability measures utilized by the utilities in either of these categories.

Summary of Conclusions - Reliability Measures & Benchmarking / Industry Information Sources

The study has identified several key industry specific publications related to reliability based performance metrics and performance benchmarking.

A review of the published literature indicates that interest in this area is increasing both within the electricity utility industry and the authorities and associations responsible for regulating the industry.

Some uniformity in the use of Transmission Reliability Performance indicators is beginning to emerge within the industry. However, electricity utilities and related regulatory authorities recognize that the inconsistent use of reliability performance measures and the related discrepancies in interpretation and data collection methodologies make inter-utility comparisons very challenging. The literature review and discussions among the working group members indicates that there is general agreement on the primary factors which can affect transmission system reliability performance, many of which are not controllable in the near term. Given the challenges of inter-utility comparisons many utilities and regulatory authorities use historical transmission system reliability performance the basis for establishing a base-line of performance, with an expectation of maintaining historical levels coupled with developing valid comparisons over time, to establish the need for improvements.

In some countries, and in broader international electricity markets, the regulatory authorities, and their related associations, seem to be taking a lead role in the investigation, development and trending of Transmission - Service Quality Indicators, including Transmission System Reliability Measures. There is also an example from Australia, where the Australian Energy Regulator is investigating measures that provide financial incentives for transmission owners to reduce expenditures coupled with the need to maintain or improve reliability for customers and to reduce the market impact of transmission congestion[1]. The Regulatory response has been to collect information on the various measures used and to report on and identify trends on a utility specific basis, with some recognition of the information issues and the complexities associated with inter-utility comparisons.

Although the electric utility industry has taken a somewhat proactive role in managing this issue, it may be prudent to respond with more aggressive analysis and the development of overall industry accepted correction factors and policies to ensure these separate regulatory initiatives do not result in the establishment of reliability based measures which are not in the best interest of customers or the electricity utilities which serve them.

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[1] Australian Energy Regulator - Electricity Transmission Network Service Providers – Service Target Performance Incentive Scheme – November 2007
http://www.aer.gov.au/content/item.phtml?itemId=716139&nodeId=84676bb3455025e319cddc36548daafc&fn=Draft%20service%20target%20performance%20incentive%20scheme.pdf

2. Detailed Study

2.1 Introduction

The main objective of the WG was to develop a broad understanding of the types of Corporate Performance Metrics currently being used across the electric utility industry, with a more detailed focus on system level reliability metrics. In accordance with the approved Terms of Reference, contained in Appendix A, the primary intent of the review was twofold:

- Establish from a corporate level perspective the metrics currently in place and identify those which are important to participating utilities across the world.

- Establish an information source related to metrics used for measuring system level reliability and other performance and cost metrics as determined appropriate.

This inventory of corporate level performance measures will provide the industry with an overview of those measures currently used by various utilities to monitor and manage the performance of the business in the most critical areas.

Through the guidance provided by the Study Committee and Working Group members the information was also assessed to identify any possible correlation between the measures employed by the various utilities participating in the study and:

- The function of the utility within the local electricity market (Transmission System Owner, Transmission System Owner and System Operator or Integrated Utility including Generation)

- The ownership structure of the utility (Public - government or Private)

2.1.1 Study Process

The process for the study involved the following for the Corporate Performance Metrics portion:

1. Establishing a base of utilities interested in participating in such a study.

2. Development of a survey to capture the performance metrics used within a company with sufficient detail for effective comparison. The survey was piloted within 2 utilities to ensure effective information would be provided and that the information was easy to obtain within most

utilities. The survey included responses from one of the utilities involved in the pilot to provide examples of the type of information and degree of detail required.

3. The participant utilities were issued the survey and results were tabulated and sent back to validate appropriate interpretation. It was found that many utilities wanted to keep the information confidential to the participating utilities. As a result two Reports were developed. One version does not attribute responses to the specific utilities and a second version was produced with responses identified by utility. The second version was only shared among the participants for the purpose of follow-up between the utilities on the effectiveness of performance measures and benchmarking of results. The version, which does not identify specific utility information, has been used for this CIGRE Technical Brochure.

4. The results of the survey were tabulated and observations were made on the overall number of performance measures used to manage performance in the various business areas, the degree of utilization of any common performance measures and the number used to manage business performance in any given business area.

5. Conclusions were developed based on the observed results and related to benchmarking efforts currently in place by regulatory authorities, industry associations and private benchmarking efforts. The participating utilities were also classified into various functional roles within the local market structure and into ownership categories (Public verses Private) to establish if these attributes affect the type of Performance Measures used.

The process for the more detailed evaluation in the area of reliability performance measures involved:

- A review of background CIGRE literature in this subject area.

- A literature review of industry documentation related to transmission business reliability measures and / or benchmarking, issued since any background CIGRE publication identified in the above step.

- Co-ordination with work associated with Joint Working Group C4 – 1 – C5.

- Discussions with Study Committee and Working Group Members and benchmarking experts.

- Documentation of available industry information in the area of reliability measures and any benchmarking efforts or findings both within the utility industry and by regulatory authorities.

- Comparison of reliability based performance measures submitted by the participating utilities, or identified in other utility industry or regulatory publications, to those recommended within the background studies found during the literature review.

- Development and documentation of conclusions based on findings related to the reliability measures and their potential use in benchmarking for business improvement and / or within regulatory settings.

2.1.2 Participating Utilities

A total of 19 utilities agreed to participate in the study providing a good overall cross section of utility characteristics, functions and ownership arrangements.

The following utilities participated in the study:

Utility	Country	Utility	Country
Continuon	Netherlands (NL)	Altalink	Canada (CA)
British Columbia Transmission Company (BCTC)	Canada (CA)	Delta Electricity	Australia (AU)
American Electric Power (AEP)	United States of America (US)	Eskom	South Africa (ZA)
Great Lakes Power	Canada (CA)	Hydro Quebec	Canada (CA)
Korean Electric Power Company (KEPCO)	Korea (KR)	National Grid	England (GB)
Gestionnaire Réseau de Transport d'Electricité (RTE)	France (FR)	Manitoba Hydro	Canada (CA)
Newfoundland & Labrador Hydro	Canada (CA)	Nordostschweizerische Kraftwerke AG (NOK)	Switzerland (CH)
Transgrid	Australia (AU)	TenneT	Netherlands (NL)
Energie Baden-Wurttemberg (EnBW)	Germany (DE)	Transba	Argentina (AR)
Hydro One	Canada (CA)		

2.2 Study Findings on Corporate Performance Measures

2.2.1 Classification of Utilities

To establish if there is any correlation between the function of the participating utilities within the local electricity market and the performance measures that they have in place, the 19 participating utilities were classified into one of the following areas:

1. Transmission System Owners, with responsibility for maintaining, replacing and expanding to asset base. Twelve of the participating utilities fall into this category.

2. Transmission System Owners / Operators, with additional responsibility for operating the local electricity system. Four of the participating utilities fall into this category.

3. Integrated Utility Owners with responsibility for Generation as well as Transmission. Three of the participating utilities fall into this category.

The utility ownership structure was also identified and the 19 utilities participating in the study were classified as either publicly (government) owned or privately owned. Of the 19 utilities participating in the study, 12 were found to be publicly owned and 7 were found to be privately owned enterprises.

2.2.2 Classification of Business Performance Areas and Results

Based on the business objectives of utilities responsible for delivering high voltage electricity Transmission services and the survey results, the corporate performance measures were categorized into the following five key business performance areas:

- **Finance / Business**
- **Safety**
- **Reliability**
- **Customer**
- **Employee**

The following sections summarize the findings of the survey results, on utilization of Performance Measures, under the five key areas mentioned above.

2.2.2.1 Finance / Business

Table B1 in Appendix B summarizes the results which provide the following key information:

Across the 19 companies participating in the study, a total of 24 performance measures were reported as being used within this category.

Of the 24 performance measures 14 are utilized by only one company, leaving 10 in use by more than one company.

The most popular measure is Net Income After Tax, which is used by 5 of the 19 companies responding to the survey.

The most popular number of measures used for the management of this business area was 2, with 8 of the 19 companies utilizing 2 measures.

The highest number of measures used by any one company was 5.

Two companies reported not using any measures in this area or decided not to provide the information.

There were no discernible trends in this measurement area related to the function of the utilities within the local market structure or the ownership structure.

The specific measures sorted by participating utility appear in Appendix C. A summary of measure definitions, where provided by the utility, are detailed in Appendix D, with Finance appearing in Table D1.

In general the **Finance / Business** measures were highly varied with "Net Income", both before and after taxes, being found to be the most common. "Credit rating" was also used and a range of financial tools such as "cash flow" are being applied. The key Business or operational measures included project monitoring procedures to ensure accomplishment of work programs.

2.2.2.2 Safety

Table B2 in Appendix B summarizes the results which provide the following key information:

Across the 19 companies participating in the study, a total of 20 performance measures were reported as being used within this category.

Of the 20 performance measures 9 are utilized by only one company, leaving 11 in use by more than one company.

The most popular measure is Serious Lost Time Injuries, which is used by 7 of the 19 companies responding to the survey.

The most popular number of measures used for the management of this business area was 3, with 8 of the 19 companies utilizing 3 measures.

The highest number of measures used by any one company was 4.

Three companies reported not using any measures in this area or decided not to provide the information.

There were no discernible trends in this measurement area related to the function of the utilities within the local market structure or the ownership structure.

The specific measures sorted by participating utility appear in Appendix C. A summary of measure definitions, where provided by the utility, are detailed in Appendix D, with Safety appearing in Table D2.

In the area of public and employee **Safety** the measures primarily focus on the frequency and severity or seriousness of injuries. The range of measures used is designed to capture the various rates of injuries, with emphasis on serious outcomes. A few measures are used to report on the managing of the safety processes.

A significant finding in this measurement area was that although there are safety related measures established by the Occupational Safety and Health Administration (OSHA), which are based on injuries for 200,000 hours worked, and the International Union of Producers and Distributors of Electrical Energy (UNIPEDE – Union Internationale des Producteurs et Distributeurs d'Energie Electrique), which are based on injuries for 1,000,000 hours worked, the majority of utilities chose to use different measures. The safety measures utilized by many of the utilities were based on injuries per 100,000 hours worked or injuries per total number of employee man-hours of exposure.

It should be noted that many utilities provided Safety related information under the Employee measure in the survey responses.

2.2.2.3 Reliability

Table B3 in Appendix B summarizes the results which provide the following key information:

Across the 19 companies participating in the study, a total of 22 performance measures were reported as being used within this category.

Of the 22 performance measures 12 are utilized by only one company, leaving 10 in use by more than one company.

The most popular measures are System Average Interruption Duration Index (SAIDI) and Unsupplied Energy (UE). Both SAIDI and UE are used by 9 of the 19 companies responding to the survey.

The most popular number of measures used for the management of this business area was 3, with 6 of the 19 companies utilizing 3 measures.

The highest number of measures used by any one company was 6.

The only common factor which could be identified in this measurement area, related to the function of the utilities within the local market structure, was the consistent use of the Unsupplied Energy measure when the utility had the responsibility for operating the local electricity system.

There were no discernible trends in this measurement area related to the ownership structure.
The specific measures sorted by participating utility appear in Appendix C. A summary of measure definitions, where provided by the utility, are detailed in Appendix D, with Reliability appearing in Table D3.

The **Reliability** measures used primarily focus on the two key areas of frequency and duration of outages. A significant number of “unsupplied energy” and “unavailability” measures are also present. These measures were sometimes supplemented by specific or specialized measures.

2.2.2.4 Customer

Table B4 in Appendix B summarizes the results which provide the following key information:

Across the 19 companies participating in the study, a total of 19 performance measures were reported as being used within this category.

Of the 19 performance measures 13 are utilized by only one company, leaving 6 in use by more than one company.

The most popular measures are Customer Satisfaction Surveys of Transmission Load Customers; Transmission Generation Customers and Commercial Customers. These types of surveys are used by 3 of the 19 companies responding to the survey.

A total of 8 of the 19 companies do not use this type of measure. Of the 11 companies using this type of measure, the most popular number of measures used for the management of this business area was 2, with 6 of the companies utilizing 2 measures.

The highest number of measures used by any one company was 5.

Eight companies reported not using any measures in this area or decided not to provide the information.

There were no discernible trends in this measurement area related to the function of the utilities within the local market structure or the ownership structure.

The specific measures sorted by participating utility appear in Appendix C. A summary of measure definitions, where provided by the utility, are detailed in Appendix D, with Customer appearing in Table D4.

While a number of **Customer** measures are listed they tend to be variations on customer surveys. However, there appears to be an emerging trend towards using surveys which are segmented by customer groups rather than general surveys. The results also indicate that utilities are monitoring the implementation of survey comments by tracking specific initiatives designed to respond to customer concerns and thereby improve customer satisfaction.

2.2.2.5 Employee

Table B5 in Appendix B summarizes the results which provide the following key information:

Across the 19 companies participating in the study, a total of 18 performance measures were reported as being used within this category.

Of the 18 performance measures 17 are utilized by only one company, leaving only 1 in use by more than one company.

The performance measures in this area are unique to the companies, with the exception of 2 companies utilizing an Employment Engagement Index. This Employee Engagement Index is based on the extent of employee alignment, capability, resources and motivation. Four companies use employee surveys as a means of obtaining the required information.

A total of 10 of the 19 companies reported no use of such a measure or decided not to provide the information.

Of the 9 companies using this type of measure, the most popular number of measures used for the management of this business area was 1, with 6 of the 9 companies utilizing only 1 measure.

The highest number of measures used by any one company was 7.

There were no discernible trends in this measurement area related to the function of the utilities within the local market structure or the ownership structure.

The specific measures sorted by participating utility appear in Appendix C. A summary of measure definitions, where provided by the utility, are detailed in Appendix D, with Employee appearing in Table D5.

The **Employee** measures are more varied than the other measures but generally focus on employee surveys / satisfaction, with equity issues, and planning for the future through the use of training measures also being utilized.

2.3 Conclusions – Corporate Level Performance Measures

This work provides the industry with a good sample of performance metrics utilized by several utilities across the world.

The information provided by the participating utilities indicates that there is a wide disparity in the performance measures used by utilities across the world. This is especially true when considering the variations used in definitions and the interpretation of the detailed data required for calculating the various performance measures. The wide disparity is even noticeable for key transmission company performance indicators such Employee and Public Safety and Transmission System Reliability.

Overall a detailed review of the survey information indicates that many of the measures, which are related to a similar business area, have different detailed attributes, interpretation details and data collection requirements.

Performance measures are typically established within a company to measure the success in meeting various strategic business objectives, which are set and monitored by the Board of Directors and Leadership Team of the company. The strategic objectives are typically a function of return requirements of the Shareholders, risk tolerance of the Leadership Team, historical performance of the business, degree of customer satisfaction and compliance requirements of local regulatory authorities. The variability in the utility specific strategic business objectives (and the fact that management judgement must be applied in establishing the related performance measures) likely accounts for the wide disparity of performance measures used, even though the utilities are all operating the same technical business.

The wide disparity of performance measures currently in place within the electricity utility industry and the related disparity in interpretation details and data collection requirements make accurate benchmarking an extremely challenging endeavour.

The analysis related to the use of specific performance measures in relation to the function of the utility within the local market structure found that only the Reliability performance measures showed any discernible trend. The analysis of results indicated that utilities performing both the system owner and operator role within the local market structure make consistent use of the **Unsupplied Energy** measure for managing / monitoring Transmission system reliability.

There were no discernible differences in the measures utilized between publicly versus privately owned companies. This may be a result of the fact that today many publicly owned companies are expected to operate as private commercial enterprises. Typically the executive and management teams of these companies are selected on the basis of business acumen and are expected to operate the companies on a fully commercial basis.

The industry review of benchmarking documentation indicates that interest in this area is increasing with regulatory authorities and / or regulatory associations taking on a leading role in many countries or in broader international markets.

The Regulatory response has been to begin collecting information on the various measures used and to report on and identify trends, with some recognition of the information issues and the degree to which the information is comparable.

2.4 Study Findings - Reliability Measures & Benchmarking / Industry Information Sources

In response to the objective of **establishing an information source related to metrics used for measuring system level reliability** the study includes a review of background CIGRE literature and recent industry documentation related to transmission business reliability measures and benchmarking.

The background review uncovered **CIGRE Joint Working Group (JWG) Report C4.07 / CIRED; entitled POWER QUALITY INDICES AND OBJECTIVES,** dated January 2004 / revised March 2004. This work was issued as CIGRE Technical Brochure 261 in October 2004.

The recent industry literature review concentrated on identifying key industry (including regulatory) based documentation on Transmission Reliability Performance Measures, issued since the work of **CIGRE JWG C4.07 / CIRED**.

Also included is an assessment of the degree of application of the reliability measures recommended for use within the **CIGRE JWG C4.07 / CIRED Report**. The degree of application of these recommendations was investigated for the 19 utilities participating in this study and for utilities participating in any other publicly available industry surveys, conducted since the 2004 **CIGRE JWG C4.07 / CIRED Report** was issued.

4.1 Background CIGRE Literature

The **CIGRE JWG C4.07 / CIRED Final Report** on **Power Quality Indices and Objectives**, dated January 2004 (revised March 2004) investigated existing indices used for measuring Power quality, including indices for “long interruptions”. These indices for long interruptions match the definition of continuity of supply or system reliability. The **CIGRE JWG C4.07 / CIRED Report** investigated existing reliability based indices in use (covered in Section 2.5 of the Report); reviewed measurement data and provided comments on benchmarking and comparative reporting (covered in Section 3.5 of the Report); recommended quality indices (covered in Section 4.5 of the Report) and quality objectives (covered in Section 5.6 of the Report).

The study found that "transmission interruption reporting differs significantly from utility to utility" and can be divided into the following categories:

- **Number of events:** *actual number of events* and *the average number of events* over the reporting period (i.e. the latter is the frequency of events);
- **Duration of events:** *average total duration of events* over the reporting period and *average time to restore supply per interruption* at each supply point. The *availability of the supply* is the converse of the duration and it gives an indication of the relative risk of interruptions;
- **Severity of events:** *severity of the interruption events* over the reporting period (i.e. the size of load affected) and indices estimating the *cost impact per event.*

The principle conclusions of this Report related to reliability benchmarking are summarized below:
"A conclusion on inter-utility benchmarking formulated by the IEEE/PES working group on system design is that performance "*cannot be compared between companies by simply comparing indices...many other factors must be taken into consideration.*"
"A similar conclusion was reached this year in an Australian attempt at international transmission system benchmarking, i.e. the Australian experience is that these problems make *"inter-company and international comparisons difficult if not impossible.*"

"The benchmarking of transmission performance is complicated by the combination of unique influencing factors in each country (geography, environmental conditions, load density, the location of generation sources, the degree of excess capacity, network topology, system voltage levels). The dominant benchmarking approach for Transmission companies is therefore based on historical performance of the company itself. This is evident in various countries such as the UK's (OFGEM's work related to the BETTA project - which acknowledges the need for "geographic" differentiation in its proposed standards), Australia (ACCC's project to benchmark each of its transmission companies by the end of the year, based on the last 5 years of data for each utility), New Zealand (TransPower's specific differentiation of planned and unplanned system minutes due to the radial nature of its system)."

For establishing performance measures, the Report recommends the adoption of one or more of the following three philosophies, which describe different aspects of interruption performance:

- **Connection Point Interruption Performance (CPI);**
- **End-Customer Load Interruption Performance (CLI);**
- **System Interrupted Energy Performance.**

The recommended indices for the CPI philosophy are as follows:

- **Average frequency of sustained connection point interruptions per year: SAIFI-CPI;**
- **Average frequency of momentary connection point interruptions per year: MAIFI-CPI;**
- **Average total duration of all sustained connection point interruptions per year: SAIDI-CPI (see note below);**
- **Average duration of a sustained connection point interruption during the year: SAIRI-CPI (see note below).**

Note: ***Similar indices for momentary events are not meaningful and by including momentary events with sustained events in SAIDI, SAIRI, these indices will improve for more momentary events.***

Under the definitions for the above indices **momentary** interruptions are those of less than or equal to 1 minute and **sustained** interruptions are those of greater than 1 minute.

The recommended indices for the CLI philosophy are outlined in the following Table 4.1-1 below:

Table 4.1-1

Categorization	***Definition***	***End-Customer Load Interruption Performance (CLI) Philosophy***
Frequency	Average Frequency of Interruptions per year* (number / year)	SAIFI (sustained)* MAIFI (momentary)*
Frequency	Number of interruption events associated with load loss (no. / year)	No. of System Minute events with system minutes of degree 0,1,2,3** **OR** Number of load interruption events
Frequency	Number of forced load reduction events – no delivery point interruption (no. / year)	Number of forced load reduction events (NLRE)
Individual interruption duration	Average duration of customer interruption* (min)	CAIDI*
Total duration of interruptions	Average total duration of customer interruptions per year* (min/year)	SAIDI*
Interruption Severity	System minutes (system min / year)	Sum of system minutes for events < 1 system minute Individual event severity for system minute events > 1 reported individually

Availability / Unavailability	System energy availability (%) or System energy unavailability	Availability **OR** Unavailability

*** NOTE (DX): Customer load loss philosophy can be applied according to distribution rules for defining customers. This provides some alignment between performance of the distribution company and the transmission company. Use of this philosophy however requires knowledge of the number of customers affected for each event (this can only be provided by the distribution company). Use of a unique definition of the number of customers is not recommended, however where this is used, the unique definition should be clearly described when reporting.**

****Definition for degree levels 0,1,2,3 appear in Table 4-2 below.**

The recommended indices for the System Interrupted Energy Performance philosophy are as follows:

The following system index definitions are recommended:

***System Average Interruption Time (AIT)*:**

$$AIT = \frac{\sum(EENS - SI) \times 8760 \times 60}{YEC \times 10^6}$$

Where:

EENS-SI = Estimated Energy Not Supplied for each sustained interruption (MWh);

Σ (*EENS-SI)* = sum of all EENS-SI over a 12 month period (MWh);

YEC = Yearly Energy Consumption in the system (TWh).

The calculation of EENS-SI is applied only for sustained interruptions. It may be estimated by (interrupted power x event duration).

$$\text{EENS-SI} = T \times PNS$$

Note that for distribution systems this measure may be considered an approximation of SAIDI and CML under the assumption that all customers are the same size. This assumption is not as suitable for transmission systems, where the size of a single customer may range from 10 to 1000 MW. It therefore represents a theoretical adaptation of SAIDI for the transmission system.

System Average Interruption Duration (AID):

It is calculated by:

$$AID = \frac{\sum(T.PNS)}{\sum PNS} = \frac{\sum ENS - SI}{\sum PNS} \quad \text{(min / Interruption)}$$

where:

- T = duration of each sustained interruption;
- PNS = interrupted power (it is then a weighted average in function of the interrupted power).

NOTE: For distribution systems this measure may be considered an approximation of CAIDI under the assumption that all customers are the same size. It represents a theoretical interpretation of interruption time for the system.

System Average Interruption Frequency (AIF)

It is calculated by:

$$AIF = \frac{AIT}{AID} \quad \text{(interruptions / year)}$$

***NOTE**: For distribution systems this measure may be considered an approximation of SAIFI under the assumption that all customers are the same size. It represents a theoretical interpretation of interruption probability for the system.*

General System Indices

The following indices may be applied in conjunction with any of the reporting philosophies applied. They provide additional information on the system performance.

System Energy Unavailability or Availability:

Unavailability = 100.EENS / (YEC) (%)

Availability = 100*(1 – Unavailability) (%)

EENS = Estimated Energy Not Supplied for each interruption, including monetary interruptions, sustained interruptions, and load reduction events (MWh). Only events associated with the transmission system interruptions and constraints should be included. Generation-initiated events may be excluded.

System minutes

A measure of the severity of incidents on the system. The definition is:

System minutes , i.e. energy not supplied as a function of the size of the system.

$$SM = \frac{60.ENS}{PD}$$

where:

ENS = Total Energy Not Supplied from all incidents (MWh);

PD = Peak System Demand for reporting year (MW).

The estimated energy not supplied (ENS) includes transmission-caused events where customer loads were interrupted or shed or reduced, that are not associated with a connection point interruption. It includes momentary events. ENS caused by voltage dips may be excluded. The calculation of estimated energy not served may be calculated as MW interrupted * duration of the event. Where information is available on stepped restoration, this may be calculated as the total for each restoration step.

Indices based on a severity index for individual incidents

The indices proposed are:

- ***SM <1***: The *cumulative system minute value* as a result of single events within an individual system minute contribution of less than 1 minute. This provides an indication of the annual trend in "normal" interruption severity.
- ***SM events of degree severity***: The number of customer interruption events with a given degree of severity. The degree of severity may be 1, 2, or 3, depending on the severity of the event. This provides a description of the severity of the individual events.

Table 4.1-2 System minutes degree of severity definitions

Degree	Description	SM
0	Unreliability condition normally considered acceptable for some systems	< 1
1	Significant impact on one or more customers but not considered serious	1 to 9
2	Serious impact on customers	10 to 99
3	Very serious impact on customers	>= 100

2.4.2 Recent Industry Literature Review

The industry literature review uncovered the following key documents and recommendations related to transmission business reliability measures and benchmarking, which have been published / issued, since the work of **CIGRE JWG C4.07 / CIRED**:

1. ***Electrical Power Research Institute (EPRI) - Transmission Reliability Impact Metrics Project, Final Report is dated September 25, 2007.***

The report summarizes technical recommendations from a team of transmission owner representatives (in North America) to improve transmission reliability performance assessment. The scope of this project included the long term, retrospective performance assessment of transmission reliability impacts due to transmission owner actions and facilities. The report recommendations are primarily intended for use in strategic planning applications and also for guidance in transmission regulatory policy development currently in progress.

The group selected methods and metrics on their ability to meet requirements for: comparability, simplicity, relevance, and attainability.

Previous EPRI study report recommendations included transmission facility availability metric recommendations for Deliverability and Delivery. This project augmented that work with impact metrics which quantify the significance of facility unavailability in terms of the overall functional objectives of interconnected transmission operations: interconnection integrity; transmission customer service continuity; and wholesale market function. The integration of these performance dimensions (availability and impact) is necessary because transmission owners need to know how facilities and actions, within their responsibility, significantly impact performance.

The EPRI Transmission Reliability Impact Metrics Project – Final Report, dated September 25, 2007 and was developed for Participant Distribution Only. The report can be obtained from EPRI by contacting Mr. Ram Adapa at EPRI at following e-mail address:

RADAPA@epri.com

Since this is not a publicly available report key findings, conclusions and recommendations will not be outlined within this study. It is recommended that any utility interested in the subject area obtain a copy of this important report since it represents an excellent research reference for establishing reliability performance measures.

Note: There was also an interim Report at the end of Phase 2 of this EPRI study - EPRI Transmission Grid Reliability Performance Metrics Final Report is dated July 2006. The above mentioned Final Report incorporates the results of the Phase 2 Report.

2. Council of European Energy Regulators (CEER) - Third Benchmarking Report on Quality of Electricity Supply 2005

This Third Benchmarking Report on Quality of Electricity Supply by CEER is a publicly available document on the CEER – Web site.

Chapter 1 of this report deals with Continuity of Supply and outlines the various reliability measures utilized in 20 countries covered by this version of the CEER report. The report also identifies actual available performance levels, standards and the incentives used in service quality regulation.

The analysis determined that the most common indicators used for Transmission were found to be:

a. **Energy Not Supplied (ENS)**

b. **Average Interruption Time (AIT)**

c. **System Average Interruption Duration Index (SAIDI) at the transmission level**

d. **System Average Interruption Frequency Index (SAIFI) at the transmission level.**

The main conclusions of the report include the following:

- Both the number and duration of unplanned outages are showing downward trends in most European countries.

- Excluding exceptional events from the unplanned performance figures highlights that significant improvements are being made in many European countries for both the duration and number of interruptions.

- Countries with good relative performance in the areas of frequency and duration of interruptions have been able to make further improvements.

- Short interruptions have generally not been rising despite a move toward automation and remote control techniques, as cost saving measures.

In relation to benchmarking the report indicates that "Different approaches to continuity of supply regulation, and in particular the different continuity indicators and standards adopted, recording methodologies used, combined with different geographical, meteorological and network characteristics, makes benchmarking of actual levels of continuity of supply difficult."

The report identifies several reasons for the expected differences in the reliability performance of specific utilities and the related challenges this represents to performing accurate benchmarking. The findings of CEER Report are consistent with the findings of Working Group C1.11.

Documented acknowledgment of the challenges associated with inter-utility benchmarking of transmission reliability performance measures appears in Section 4.4 of this Technical Bulletin.

3. *Canadian Electricity Association (CEA) Transmission Reliability Measure Recommendations and Policies*

Reliability of Transmission System at Delivery Points is carried out within the CEA under the Electric Power System Reliability Assessment / Bulk Electricity System (EPSRA / BES) program. Metrics proposed by the CEA - Consultative Committee on Outage Statistics (CCOS) and accepted by the CEA Transmission-Council recommended for use in a potential regulatory setting include:

Transmission System Average Interruption Frequency Index (T- SAIFI)

Transmission System Average Interruption Duration Index (T-SAIDI)

Each of these indices must be assessed annually, using forced, sustained events, to establish the Canada participant average.

Definitions for these measures are as follows:

Transmission System Average Interruption Frequency Index - Sustained Interruptions (T-SAIFI-SI)

A measure of the average number of sustained interruptions that a DP experiences during a given period, usually one year.

$$\text{T-SAIFI-SI} = \frac{\text{Total No. of Sustained Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

Transmission System Average Interruption Duration Index (T-SAIDI)

A measure of the average total interruption duration that a DP experiences during a given period, usually one year.

$$\text{T-SAIDI} = \frac{\text{Total Duration of all Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

Note: For the purpose of the above T-SAIFI index, Sustained Interruptions are defined as interruptions which are one minute or longer in duration.

Recommendations for the use of more detailed metrics (further granularity of T-SAIFI and T-SAIDI) by the CEA - CCOS to the CEA Transmission Council are pending.

Note: Reliability of Major Transmission Equipment is also carried out in the CEA Equipment Reliability Information System (ERIS) program.

As a result of the interest in benchmarking of Transmission and Distribution systems by Regulatory Authorities in many Canadian provinces, the CEA has found it necessary to develop and issue a policy statement on the use of Benchmarking Data in Regulatory Settings. This policy statement is dated June 5, 2006 and is directed at Canadian electricity industry stakeholders. The policy statement is attached as Appendix D and is available on the following web-link:

https://www3.eub.gov.ab.ca/eub/dds/iar_query/ShowAttachment.aspx?DOCNUM=667215.

Some of the primary elements of the policy statements are summarized below:

- Electricity utilities have been utilizing benchmarking for a number of years to improve operational performance, by establishing utility best practices, in a number of key business areas (continuity of service, customer satisfaction, employee safety and cost related indicators). Utilities typically perform such analysis on a confidential basis and before any information is utilized to improve business processes applicability is assessed and subject to significant degree of professional judgement. Attempts by Regulatory Authorities to use any related information for other purposes such as peer-to-peer comparisons is likely to result in incorrect results and may inhibit the important inter-utility efforts of benchmarking for the purposes of operational improvement.

- Before utilizing benchmarking information in regulatory settings an appropriate framework must be established with proper consideration of caveats, standardized interpretations and collection methodologies.

- Peer-to-peer comparisons, especially for establishing pass / fail criteria for compliance (breach and consequence) purposes is not recommended due to the complexity of identifying true "peers". The complexity is related to significant inter-utility differences which affect many performance measures, including reliability. This includes the geography and climate within which the system must operate; historic system design; system age; degree of interconnection; degree of automation and a range of other factors.

- Trending a utilities own performance over time should be used as opposed to single year comparisons between utilities.

- The CEA will work in cooperation with regulatory authorities to ensure indicators that are used in regulatory settings are accurate, verifiable and verified for use in assessing individual company performance over time.

4. CIGRE 2006 Paper C5-109; Power Transmission Performance Indices

This paper proposes standardized definitions, data compilation and calculation methodologies and reporting methods which, at the time of publication, were being adopted by some of the Power Transmission Authorities / Companies in the Gulf Cooperation Council Region.

The supply reliability indices proposed are as follows:

- **System-Minutes Lost Index**
- **System Average Interruption Frequency Index**
- **System Average Interruption Duration Index**
- **System Average Restoration Index**

These performance measures / indices were selected based on their recognition by standards authorities and other electric utilities and on their relative simplicity in compilation / calculation. The paper indicates that these indices “present quantified values from which the performance of a power system can be realistically and objectively measured and evaluated as well as highlighting potential areas where improvement is needed”. The paper also provides guidance on the use of related equipment reliability indices, which facilitate root cause analysis to “target weak areas and launch improvement plans”.

Section 6.0 of the paper covers Analysis and Benchmarking, where the paper cautions that:

- Differences in index values between areas or systems do not necessarily represent differences in the effectiveness of the company, since these differences can be considered as normal and expected due to the different equipment types installed, the system voltage ranges utilized, different operating environments and philosophies adopted over the course of the history of the utility.

- It is more meaningful to look at the long term trend of specific performance measures rather than at figures for an individual reporting period, due to the possible occurrence of rare or abnormal incidents in a particular reporting period.

- The method of reporting or recording disturbance data by a specific utility could affect the values of indices calculated and therefore the comparability between utilities.

- The performance indices of each power system should be evaluated on their own merits and only “apples versus apples” comparisons are valid.

Section 7.0 of the Paper covering Conclusions and Recommendations, provides the following conclusion, which indicates that care must be when comparing performance indices with other utilities or with different operating areas within the same utility:

“Comparison with other utilities (or with different operating areas of the same utility) on the various Performance Indices is another useful tool to evaluate how well a utility is performing or if improvement is needed in some particular areas. However, for such comparisons to be valid, they have to be made on the same platform.”

2.4.3 Comparison of CIGRE JWG C4.07 / CIRED Recommended Transmission Reliability Measures with Actual Utility Practices

The following Table 4.3-1 summarizes and compares the general reliability performance measures recommended within the CIGRE JWG C4.07 / CIRED Report in relation to the following:

- The measures utilized by the utilities participating in this study and documented in Parts 1 through 3 of this report.

- The measures identified in the CEER Third Benchmarking Report on Quality of Electricity Supply 2005.

- The Transmission Reliability Measures recommended by CEA for use in Regulator Settings.

- Transmission Reliability Measures recommended for adoption by the Power Transmission Authorities / Companies within the Gulf Cooperation Council in accordance with CIGRE 2006 Paper C5-109

Table 4.3 -1

CIGRE JWG C4.07 CIRED Report Recommendations for Long Interruptions	Similar Measures utilized by Participating Utilities [Yes / No] & (Extent of use - Number of utilities using similar measure, 19 participating)	Measures identified as used within the CEER Third Benchmarking Report 2005 [Yes / No]	CEA Recommended Measures for Regulatory Settings [Yes / No]	Measures Recommended for use within the Gulf Cooperation Council in accordance with CIGRE 2006 Paper C5-109
SAIFI	Yes (8)	Yes	Yes	Yes
MAIFI	No	Yes	No*	No
SAIDI	Yes (13)	Yes	Yes	Yes
CAIDI	Yes (1)	No	No*	Yes**
AIT	No	Yes	No*	No
AID	No	No	No*	No
AIF	Yes (8) - Similar to SAIFI	Yes - Similar to SAIFI	No*	No
SE – Unavailability	Yes (5)	No	No*	No
SE – Availability	Yes (1)	No	No*	No
SM	Yes (11) – Similar to UE	Yes – Similar to UE or ENS	No*	Yes
SM < 1	No	No	No*	No
SM events of degree severity (1,2,3)	No	No	No*	No

*** - CEA recommendation was strictly for use in Regulatory Settings, whereas CIGRE JWG C4.07 Report recommendations were for general utility measurement for utility performance monitoring and improvement.**

**** - CIGRE 2006 Paper C5-109 recommends use of a System Average Restoration Index, which by definition is equivalent to CAIDI.**

These results indicate that the recommendations of **CIGRE JWG C4.07 / CIRED** are beginning to have a significant effect on influencing the measures utilized by the electricity utility industry, in the area of system reliability.

2.4.4 Acknowledged Challenges in Inter-Utility Benchmarking of Transmission Reliability Performance

The following excerpts from some key utility industry publications in this subject area indicate that both the utility industry and its regulatory authorities recognize the challenges of identifying appropriate peer utilities, comparative reporting and benchmarking:

CIGRE JWG Report C4.07 / CIRED, entitled POWER QUALITY INDICES AND OBJECTIVES, dated January 2004 / revised March 2004.

From Section 2.5.2 (Page 37) – "The manner in which specific interruptions are dealt with can have a significant effect on the reported statistics. A review of international utility definitions applied when reporting against indices has concluded that these differ significantly from one transmission utility to another. The most significant differences are discussed below. The review has also concluded that the application of the definitions is often not clearly defined. This highlights the need for an international recommendation not only on the indices used, but also to the application of these indices in practice."

From Section 3.5.1 (Page 57) – "sources of comparative transmission performance statistics are very limited. Where differences in the specific definitions of indices are a major concern in the case comparisons of Distribution companies, Transmission companies often use very different combinations of indices. These are also often applied differently."

From Section 3.5.1 (Page 58) – "A conclusion on inter-utility benchmarking formulated by the IEEE/PES working group on system design is that performance "*cannot be compared between companies by simply comparing indices…many other factors must be taken into consideration*. A similar conclusion was reached this year in an Australian attempt at international transmission system benchmarking, i.e. the Australian experience is that these problems make *"inter-company and international comparisons difficult if not impossible*."

"The benchmarking of transmission performance is complicated by the combination of unique influencing factors in each country (geography, environmental conditions, load density, the location of generation sources, the degree of excess capacity, network topology, system voltage levels). The dominant benchmarking approach for Transmission companies is therefore based on historical performance of the company itself. This is evident in various countries such as the UK's (OFGEM's work related to the BETTA project - which acknowledges the need for "geographic" differentiation in its proposed standards), Australia (ACCC's project to benchmark each of its transmission companies by the end of the year, based on the last 5 years of data for each utility), New Zealand (TransPower's specific differentiation of planned and unplanned system minutes due to the radial nature of its system)."

From Section 4.5.4 (Page 81) – "Benchmarking interruption performance between companies requires a careful selection of comparable companies (i.e. comparable networks, environmental conditions, geography, customer density etc). It also requires that the method of calculation of indices be identical. Benchmarking interruption performance within one company against historical performance requires consistent calculation methods."

Electrical Power Research Institute (EPRI) - Transmission Reliability Impact Metrics Project, Final Report is dated September 25, 2007

From Section entitled Regulatory Performance Assessment & Enforcement (Page 40) – "Regulation based solely on availability metrics alone could invoke arbitrary penalties, since systems are designed subject to unique system user requirements, load patterns, generation attributes, and geographical, environmental, and geospatial aspects."

From Section entitled Recommendations (Page 41) – "These recommendations require a phase-in period to permit industry implementation of systems to address attainability issues. A period of at least three to five years is recommended for sufficient data accumulated to be collected and proven useful."

Council of European Energy Regulators (CEER) - Third Benchmarking Report on Quality of Electricity Supply 2005

From Section 1.2 (Page 4) – "In several countries both the number and the duration of outages are available for each indicator, but the choice of the indicator used varies by country and in many countries short interruptions (and sometimes, transient ones) are or will be recorded as well. Different approaches to continuity of supply regulation, and in particular the different continuity indicators and standards adopted, recording methodologies used, combined with different geographical, meteorological and network characteristics, makes benchmarking of actual levels of continuity of supply difficult."

From Section 1.5 (Page 7) – "Because of different measurement practices in European countries, available data on actual levels of continuity of supply are not always comparable. It is important to consider the country specific conditions detailed in the Annex to this chapter. In particular the following should be noted:

- First, whilst the scope of benchmarking interruptions has been extended to include short interruptions as well as long interruptions, not all countries separate their interruptions data into these two categories.
- Second, there are different ways of measuring supply interruptions. Continuity data may be collected at all voltage levels or may exclude some voltage levels, this will be identified later in the report. Furthermore, continuity indicators may refer to all customers or be split between customers at different voltage levels.

· The final and perhaps most important factor to take into consideration is that continuity indicators are not always defined in a comparable way. Continuity indicators can be weighted by three different methods; by customer, transformer or contracted power. This can give rise to differences depending on which weighting method is used.

Measurement practices have an important role in the definition of standards and in the design of incentive/penalty regimes. The relationship between continuity measurement systems and standards and/or incentive/penalty regimes will be discussed in depth."

From Section 1.5.1 (Page 7) – "*It is clear from the survey that significant differences exist with regard to accuracy, as well as completeness in the measurement and registration of the data. In addition, monitoring of continuity data by the regulators is a fairly recent activity for numerous countries. Robust data would require at least three years of historical measurements, consistent with unambiguous recording rules. Consequently, even if most of the regulators indicated in the questionnaire that they register long interruptions, fewer countries met the requirements chosen for inclusion in the data comparison.*"

From Section 1.6 (Page 9) – "Comparative analysis is facilitated where countries use the same method for calculating continuity indicators at all voltages".

From Section 1.6.4 (Page 17) – "The survey shows that fewer than half of the surveyed countries regularly conduct audits on continuity data provided by the companies".

From Section 1.7 (Page 19) – "Care must be taken when comparing countries' figures not only because there are a number of methods employed for calculating the continuity indicators, but also because of differences in the scope of interruptions covered, the rules determining how interruptions are counted and the robustness of the data itself."

From Section 2.2.1 (Page 34) – "Comparison of data across countries is made inherently difficult by the fact that performances vary substantially even among companies and within the same company. As suggested by Ofgem, factors that influence performance can be grouped into three classes:

· **Inherent factors** such as weather conditions, geography and population density of a particular area;

· **Inherited factors** such as the design of the network at the starting moment of incentive regulation and/or privatisation (e.g. some companies or areas may have long, predominantly overhead circuits, whilst others may have more underground lines). It takes a long time and significant capital expenditure to fundamentally alter network design;

· **Incurred factors** such as managerial performance, how well assets are maintained, and how effectively resources are used."

Canadian Electricity Association (CEA) Policies on the use of Benchmarking Data in Regulatory Settings

From Section entitled Best Practices and Performance Improvement (Page 1) – "The primary purpose of CEA's benchmarking efforts over the past two decades has been to assist member in improving their operational performance. Since the main focus of these efforts was to improve operational performance, through the identification of utility "best practices", the data collection methods were not of sufficient quality for use in benchmarking for Regulatory purposes.
Participation in benchmarking studies is typically voluntary. Regulatory actions using data for purposes it was not intended is likely to result in incorrect results and could therefore inhibit participation in benchmarking activities for the purpose of operational improvement."

From Section entitled The Challenges of Peer Group Benchmarking (Page 1) – "By its very nature, "peer group" benchmarking is an extremely challenging undertaking. Attempts to account for unique operating and business environments are complex and require detailed information. This detailed information, while more than adequate for the "discovery" process which is at the heart of performance benchmarking, is often not of sufficient quality to be used in regulatory environments."

From Section entitled The Policies / Subsection Developing the Framework (Page 2) – *"Appropriate benchmarking performance information (which is accurate, verifiable, and verified and includes the proper consideration, caveats, standardized interpretations and collection methodologies) will be developed by CEA for use in Regulatory settings."*

From Section entitled The Policies / Peer-to-Peer Not Recommended (Page 2) – *"CEA members do not support a peer-to-peer approach when assessing a company's performance and especially to establish pass/fail criteria for breach and consequence, due to the* *complexity of identifying true "peers". This complexity is due to differences between companies' geography, climate, customer mix, growth rate, system age, resource mix, degree of interconnection, impact of significant events, and a range of other factors."*

CIGRE 2006 Paper C5-109 Power Transmission Performance Indices

From Summary Section of Paper (Page 1) – "When comparing performance with other utilities, it should be well understood that while the general methodology for calculating PI's is common among utilities, there are great variations in definitions on the terms and events related to data compilation, assumptions, inclusion and/or exclusion criteria, etc."

From Section 6.0 of Paper (Page 12) – "Such analysis can determine reliability in a given area (geographical, political, operating. etc) and determine how factors such as design differences, environmental or maintenance methods and operating practices affect system performance."

From Section 6.4 of Paper (Page 14) – "It should be pointed out that the differences in the index values between areas or systems do not necessarily represent differences in performance. These differences can be considered as normal and expected, resulting from different equipment types installed (such as Gas Insulated Switchgears which are inherently more reliable compared to conventional substations which are more vulnerable to bad weather but faster to restore when interrupted), system voltage range and/or different operating environments and philosophies adopted."

From Section 7.0 of Paper (Page 14) – "Comparison with other utilities (or with different operating areas of the same utility) on the various Performance Indices is another useful tool to evaluate how well a utility is performing or if improvement is needed in some particular areas. However, for such comparisons to be valid, they have to be made on the same platform."

2.4.5 Reliability Performance Measures Survey Results Relative to Findings from Benchmark Studies Identified in Section 2.4.4

Survey results for the Reliability Measures appearing in Appendix B – Table B3, Appendix C and Appendix D of this Technical Brochure indicate that, for the 19 utilities participating in the survey, there is a wide disparity in:

- The Performance Measures used
- The interpretation of the measures

- The data collection methodologies utilized

These results are consistent with those appearing in the studies mentioned in Section 2.4.4 of this Technical Brochure.

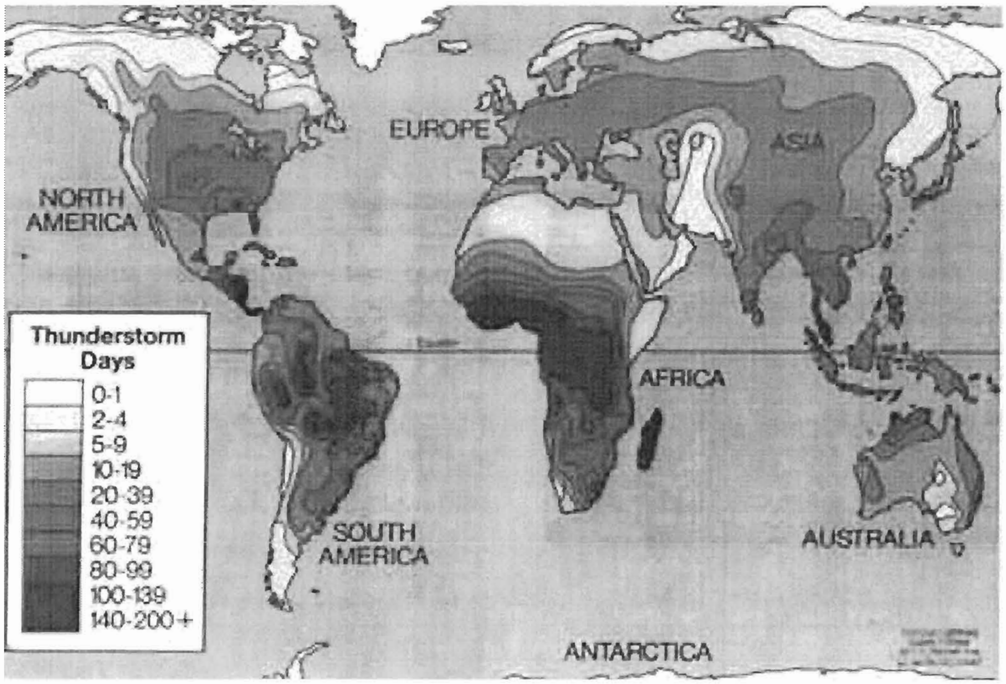
2.4.6 Working Group Discussions on Key Factors Impacting Benchmarking Studies

The Working Group members concur with the cautionary statements outlined in Section 4.4 of the Technical Brochure. In addition, the members believed it was prudent to document the following factors which could significantly affect the relative performance of transmission systems:

- Total length of transmission system lines (circuit length and route length, by voltage level)
- Number and severity of storms (lightning, wind, snow, ice, etc) to which the system is subjected
- Voltage levels utilized within the transmission system
- Number of breakers and / or automatic switches, to represent the degree of system segmentation available (average length of line in urban areas, average length of line in rural areas)
- Scale of service territory and proportion of which is urban and rural, affects response times
- Key design parameters of system (basic insulation levels, design parameters for shielding of lines and stations, grounding practices, protection and control philosophy, breaker philosophy)
- Point of measurement between the transmission system and its customers
- Average age of system
- Degree of system automation
- Number of customer connection points
- Reliability Standards

Weather has a significant impact on the frequency and duration of outages for overhead high voltage transmission systems. A review of typical utility performance statistics indicates that this factor alone can cause between 40% and 60% of the transmission system frequency based events. The impact of weather on transmission system duration based measures can be in the 20% to 40% range. Given these potential impacts, the following World Lightning Map (which shows the number of thunderstorm days in various areas around the world) provides a good indication of the extent to which geographic location can affect transmission system performance. A transmission system with identical design characteristics, and operator response times, which is installed in different areas having significantly different storm intensities, is likely to deliver significantly different reliability performance.

World Lightning Map (Average U.S. Thunderstorm Days/Year)



2.4.7 Generally Accepted Practices for Establishing a Baseline of Transmission Reliability Performance

The literature review has identified that the most common industry practice for establishing a baseline of Transmission Reliability Performance consists of identifying one or more generally accepted reliability measures and establishing the historical level based on best available information. Most utilities and regulatory authorities expect the historical level to either be maintained or incrementally improved based on careful consideration of customer satisfaction, economic evaluation and the extent and pace of system expansion and refurbishment / replacement.

This approach provides for customer needs while ensuring that the investments needed to improve the transmission system reliability performance are prudently incurred. The approach also provides time for the industry to potentially develop generic guidelines for determining the economic level of performance for each unique utility situation or appropriate comparative measures coupled with the related correction factors.

The following excerpts from some key electricity utility industry publications in this subject area validate that that establishing a historical reliability baseline is the dominant approach:

CIGRE JWG Report C4.07 / CIRED, entitled POWER QUALITY INDICES AND OBJECTIVES, dated January 2004 / revised March 2004.

Section 5.6 (Page 88) – "The dominant benchmarking approach for Transmission companies is therefore based on historical performance of the company itself."

Electrical Power Research Institute (EPRI) - Transmission Reliability Impact Metrics Project, Final Report is dated September 25, 2007

Note - This Report is not applicable, as the primary purpose of the report was to evaluate, develop and recommend transmission reliability impact metrics and adjunct methodologies. The report does not reference historical practices or interim methodologies, such as those currently in place as best practice.

Council of European Energy Regulators (CEER) - Third Benchmarking Report on Quality of Electricity Supply 2005

From Section 2.3.3 (Page 43) – "Five out of eight regulators require distribution companies to improve their performance over time."

From referenced CEER Report – Quality of Electricity Supply: Initial Benchmarking on Actual Levels, Standards and Regulatory Strategies dated April 2001 - 3.4 Continuity of Supply Standards (Page 31) – "Generally, improvement standards are differentiated according to the starting level and/or the track of past performance."

Canadian Electricity Association (CEA) Policies on the use of Benchmarking Data in Regulatory Settings

From Section entitled The Policies / Trending Performance (Page 2) – "Trending an individual utility's own performance over time should be used as opposed to single year comparisons."

CIGRE 2006 Paper C5-109 Power Transmission Performance Indices

From Section 6.4 entitled Benchmarking (Page 14) – "Therefore, it would be more meaningful to look at the long term trend of PI values rather than at an individual reporting period's figure."

"Moreover, as mentioned previously, the method of reporting and recording disturbance data by a utility could affect the values of indices calculated. The performance indices of each power system should be evaluated on their own merit. This means only "apples versus apples'" comparisons would be valid."

From Section 7.0 entitled Conclusions and Recommendations (Page 14) – "By analysing the various PIs (in particular, their trends over a long period), potential problematic areas may be identified, for an electric utility to focus its efforts for their improvement."

"Comparison with other utilities (or with different operating areas of the same utility) on the various Performance Indices is another useful tool to evaluate how well a utility is performing or if improvement is needed in some particular areas. However, for such comparisons to be valid, they have to be made on the same platform."

Appendix F provides a specific example of a regulatory submission from a transmission company, which establishes a baseline of transmission system reliability performance based on historic reliability performance at the delivery point to customers, consistent with the above findings.

The regulatory submission, which has been approved by the regulator, is based on maintaining the historical level of transmission system reliability which has been experienced at customer delivery points over a ten year period. The submission sets minimum performance standards for delivery points supplying various load levels and provides for maintaining the historic level of each delivery point within a specific band of performance going forward.

2.4.8 Effect of Utility Market Function and Ownership Structure on Reliability Performance Measures

As mentioned in the Corporate Performance Measures section of this report, the only common factor which could be identified when reviewing the information in accordance with the typical structural arrangements was that all participating utilities having responsibility for both owning and operating the local electricity system, utilize the **Unsupplied Energy** measure for Transmission system reliability.

The ownership arrangement (public or private) had no effect on reliability measures of the 19 participating utilities.

2.5 Conclusions - Reliability Measures & Benchmarking / Industry Information Sources

The study has identified several key industry specific publications related to reliability based performance metrics and performance benchmarking.

A review of the published literature indicates that interest in this area is increasing both within the electricity utility industry and the authorities and associations responsible for regulating the industry.

Some uniformity in the use of Transmission Reliability Performance indicators is beginning to emerge within the industry. However, electricity utilities and related regulatory authorities recognize that the inconsistent use of reliability performance measures and the related discrepancies in interpretation and data collection methodologies make inter-utility comparisons very challenging. The literature review and discussions among the working group members indicates that there is general agreement on the primary factors which can affect transmission system reliability performance, many of which are not controllable in the near term. Given the challenges of inter-utility comparisons many utilities and regulatory authorities use historical transmission system reliability performance the basis for establishing a base-line of performance, with an expectation of maintaining historical levels coupled with developing valid comparisons over time, to assist in establishing the need for improvements.

In some countries, and in broader international electricity markets, the regulatory authorities, and their related associations, seem to be taking a lead role in the investigation, development and trending of Transmission - Service Quality Indicators, including Transmission System Reliability Measures. There is also an example from Australia, where the Australian Energy Regulator is investigating measures that provide financial incentives for transmission owners to reduce expenditures coupled with the need to maintain or improve reliability for customers and to reduce the market impact of transmission congestion[2]. The Regulatory response has been to collect information on the various measures used and to report on and identify trends on a utility specific basis, with some recognition of the information issues and the complexities associated with inter-utility comparisons.

Although the electricity utility industry has taken a somewhat proactive role in managing this issue, it may be prudent to respond with more aggressive analysis and the development of overall industry

[2] Australian Energy Regulator - Electricity Transmission Network Service Providers – Service Target Performance Incentive Scheme – November 2007
http://www.aer.gov.au/content/item.phtml?itemId=716139&nodeId=84676bb3455025e319cddc36548daafc&fn=Draft%20service%20target%20performance%20incentive%20scheme.pdf

accepted correction factors and policies to ensure these separate regulatory initiatives do not result in the establishment of reliability based measures which are not in the best interest of customers and the electricity utilities which serve them.

Appendix A

Terms of Reference

CIGRE STUDY COMMITTEE N° C1

PROPOSAL FOR CREATION OF A NEW WORKING GROUP *

WG **C1.11**	**Name of Convenor : Joe Toneguzzo, Hydro One Canada**

Title of the Group : Asset Management - Performance Benchmarking

Background :

Performance benchmarking, although intensively time-consuming, is an area that is of growing importance in countries with a liberalised structure, due to the fact that Transmission Businesses are typically regulated and the regulating authority has interest in using benchmarking for the purpose of monitoring utility performance and costs. Benchmarking results are also of interest to Senior Management and Directors of the Board for the company, as results can be used to compare efficiency and performance between companies providing the same service and can be useful in identifying utility best practices, for business improvement.

This proposal is focused on developing a broad understanding of the types of Corporate performance metrics being used across our industry, with a detailed focus on system level reliability metrics. The intent of this review is twofold:

1. Establish from a Corporate level perspective the metrics currently in place and identify those which are important to participating utilities across the world. Based on this result, interested Committees can follow up on specific benchmarking interests.
2. Establish an information source related to metrics used for measuring system level reliability and other performance and cost metrics as determined appropriate.

Such an investigation would gain importance if both users and providers of these benchmarks (of transmission performance and potentially cost) would join the discussions to develop common definitions that would allow for accurate comparisons and opportunity for improving performance, and would evolve over time.

The work is relevant to many study committees requiring close co-operation, WG members from these SC's will be encouraged.

Deliverables

1. The work will start with developing an inventory of current Corporate level performance metrics including definitions and criteria. Companies producing and using corporate level performance metrics will be asked for their experiences via a short and easy to apply questionnaire.
2. A subsequent survey will focus on historical results for Corporate level system reliability metrics tracked and utilized within each participating company. Comparative results will be collected and reported in a manner, which protects the confidentiality of participating utilities. There may be a longer-term aim of potential best practice learning, based on the results. This will be co-ordinated with the activities of joint working group JWG C4-1-C5.
3. Two publications are expected. The first covering the inventory of Corporate level performance metrics including a description of specific goals and characteristics. The second covering the comparative results of participants in the more detailed reliability review, using methods, which protect utility confidentiality.

Time Schedule : Start : September 2006 **Final Report :** April 2008

Comments from Chairmen of SCs concerned :

Approval by Technical Committee Chairman : **Aldo Bolza**

Date :July 27 2006

Appendix B

Compilation of Results

Appendix B
Table B1

FINANCE/BUSINESS (n)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
WPA[1]								*										*	
Major Project Status				*				*								*			
Net Income AFTER Tax	*						*	*						*		*			*
Net Income BEFORE Tax					*	*	*									*			*
Credit Rating				*				*								*			
Capital Cost Management	*	*										*							*
O & M		*																	
EBITDA																		*	*
OPER-CASH																		*	
Regulatory Process & Rules		*																	
OMA			*								*								
ROE					*														*
Cash Flow (Forecasting Accuracy)						*						*							*
Benefits (Ts)									*										
Efficiency									*										
Controllable Unit Costs Method													*						
EVA[3]										*									
Operating Income										*		*							
Interest Coverage											*								
Debt/Equity Ratio											*								*
Capital Financing Ratio											*								*
Regulatory Income																*			
Net Profit Ratio				*															
Minimum Solvency Ratio[4]				*															

(n) This is only to show the "general" overview of the Finance and Business Measurements based on *similarities*
(NOTE: The definition or the concept may vary in terms of details, IFRS, International Financial Report Standards, CICA (Canadian Institute of Chartered Accountants) /AICPA (American Institute of Certified Public Accountants) and etc…)

[1]Work Program Accomplishment
[2]Either Net Income before Tax or Net Income after Tax (does not specify on the survey)
[3]Economic Value Added
[4]On the basis of IFRS
[5] EBITDA: Earnings before Interests, Taxes, Depreciation, Amortization
[6] Operating Cash: Cash generated before interests.

Appendix B
Table B2

SAFETY [(n)]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Serious Incidents								*										*	
Serious Lost Time Injuries			*		*		*	*				*						*	*
ASR[1]		*					*	*		*	*								
LTIFR[2]				*		*	*	*	*			*							
AIFR[3]	*									*	*								
OHSA-RIR[4]		*																	
PVA[5]		*																	
SMSA[6]																			
I-ELT[7]																			
Safety Index					*														
Sick Leave					*											*			
TRIR[8]						*													
DIIR[9]						*							*						
High Risk Incidents							*				*								
Near Miss Reports													*						
DMAI[10]													*						
# of Accidents & Incidents				*												*			*
FSI[11]										*									
MCS[12]																*			
APIE[13]				*															

[(n)] This is only to show the "general" overview of the SAFETY Measurements based on *similarities*
(NOTE: The definition or the concept may vary in terms of details and specifics)

[1]Accident Severity Rate
[2]Lost Time Injury Frequency Rate (similar to LTIR, Lost Time Incident Rate)
[3]All Injury Frequency Rate
[4]OHSA Recordable Incident Rate
[5]Preventable Vehicle Accidents
[6]Safety Management System Activities
[7]Information metric to ELT
[8]Total Recordable Incident Rate
[9]Disabling Injury Incidence Rate
[10]Disabling and Medical Aid Injuries
[11]Frequency Severity Index
[12]Medical Care Survey
[13]Average Percentage of Ill Employees

Appendix B
Table B3

RELIABILITY [n]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
SAIDI-DP (Duration)	*		*				*	*					* Ts		*	*		*	*
SAIFI-DP (Frequency)							*	*					* Ts					*	*
SAIDI-Customer (Duration)		*								*	*		* Ds				* MWh		
SAIFI-Customer (Frequency)										*	*		* Ds						
UE							*	*				*	*	*	*	*		*	*
UE[1]	*																		
Unavail				*				*				*						*	*
SARI						*							*					*	*
# of Incidents /Outages																*			
Vulnerability																			*
# of event w/ loss of supply														*			*		
CAIDI				*															
CML[2]				*															
CAIDA[3]				*															
NERC[4]					*				*										
SML[5]						*													
Ts Cont[6]									*										
RVR[7]										*									
AAA[8]												*					*	*	
Av of B[9]						*													
WCF[10]													*						
WDAFOR[11]													*						

[n] This is only to show the "general" overview of the Reliability Measurements based on *similarities* among the measures (NOTE: The definition or the concept may vary in terms of details and specifics)

[1]Unsupplied Energy per total number of DP
[2]CML = # of customers x total restoration time (in minutes)
[3]CAIDA: the total amount of CML/the total number of customers and the time period (minutes)
[4]North American Electric Reliability Corporation
[5]System Minutes Lost (similar to UE)
[6]Transmission Continuity
[7]Regulated Voltage Ratio
[8]Average Annual Availability
[9]Availability of Bays
[10]Weighted Capability Factor
[11]Weighted DAFOR

Appendix B
Table B4

CUSTOMER [(n)]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
CSS-Tx[1]						*		*										*	
CSS-Gs[2]						*		*									*		
CSS-Ds[3]				*													*		
CSS-Com[4]			*														*	*	
CSS-Gov[5]			*																
CSS-PS[6]			*														*		
ACMP-Tx[7]							*												
ACMP-Gs[8]							*												
ACMP-Ds[9]																			
CSS-G[10]										*									
CSS-U[11]										*									
Retail Rates-Electricity											*								
Retail Ds-Natural Gas											*								
CSI[12]											*								
Public Contact											*								
Natural Gas Market Share											*								
Power Quality												*							
CSI-Residential[13]													*						
CSI-Commercial[14]													*						

[(n)] This is only to show the "general" overview of the CUSTOMER Measurements based on *similarities*
(NOTE: The definition or the concept may vary in terms of details and specifics.)

[1]Customer Satisfaction Survey of Tx Customers
[2]Customer Satisfaction Survey of Gs Customers
[3]Customer Satisfaction Survey of Ds Customers
[4]Customer Satisfaction Survey of Commercial
[5]Customer Satisfaction Survey of Government
[6]Customer Satisfaction Survey of Public Stakeholders
[7]Annual Customer Meetings and Presentations - Tx
[8]Annual Customer Meetings and Presentations - Gs
[9]Annual Customer Meetings and Presentations - Ds
[10]Customer Satisfaction Survey hosted by Government
[11]Customer Satisfaction Survey hosted by Utility
[12]Customer Service Index
[13]Customer Satisfaction Index - Residential
[14]Customer Satisfaction Index - Commercial

Appendix B
Table B5

EMPLOYEE (HR) (n)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
EEI-ACRM[1]			*	*															
ESI[2]					*														
ATDE[3]					*														
AASDE[4]					*														
HRDSI[5]						*													
TSM[6]						*													
SRSI[7]						*													
HRSI[8]						*													
RE[9]						*													
GE[10]						*													
Disability						*													
ESS[11]																*			
CMCS[12]																			
Labour Productivity										*									
NEL %[13]											*								
DGM %[14]											*								
Training Hours/ Year																			*
Employee Development														*					

(n) This is only to show the "general" overview of the EMPLOYEE or HR Measurements based on *similarities*
(NOTE: The definition or the concept may vary in terms of details and specifics. And, it is also noted that several utilities often use the term of EMPLOYEE as the combination of HR, Human Resource practices, and SAFETY while some of the measurements for EMPLOYEE and SAFETY may be used for both purposes)

[1]Employment Engagement Index – ACRM (Alignment, Capability, Resources, Motivation)
[2]Employee Survey Index
[3]Annualized Training Days per Employee – Training
[4]Annualized Average Sick Day per Employee – Sick Leave
[5]HR Development Strategies & Initiatives
[6]Tx Succession Management
[7]Staff Retention Strategy & Initiatives
[8]Human Resources Sustainability Index
[9]Racial Equity
[10]Gender Equity
[11]Employee Satisfaction Survey
[12]Company Medical Care Survey
[13]Percentage of non-entry (NEL) positions filled by external applicants
[14]Percentage of designated group members in utility Workforce

Appendix C

Utility Specific Measurement Profiles

Appendix C
Utility Specific Measurement Profiles

Utility 1.

1-A. Measurement Areas:

1. Employee

- All Injury Frequency Rates of Employees and Contractors (Lost Time Incidents and Medical Aids Included)
- AIFR = (Medical Aid Injures + Lost time Injuries) / 200,000 hours worked

2. Financial

- Net Income After Tax in accordance with *CICA Generally Accepted Principles* for the Year End
- Capital Cost Management: Managing Actual Capital Project Costs

3. Reliability

- Duration of Delivery Point Interruptions
- Unsupplied Energy (UE) = $\dfrac{Total\ MWh\ Interrupted}{Total\ \#\ of\ DPs}$

4. Other

- Key Business Accomplishment (i.e. Regulatory Hearing Processes)
- Major Project Status (*Budget* and *Schedule*)

Utility 2.

2-A. Measurement Areas:

1. Financial

- O&M Variance: O&M Variance vs. Actual Expenditures
- Capital Variance: Capital Variance vs. Actual Expenditures
- Regulatory Process: Successful Conclusion Rates of Cases at Federal and State Level

2. Operational

- $SAIDI = \sum Customer\ Interruption\ Duration\,/\,Total\ Number\ Of\ Customers\ Served$
- Commission Complaints (excluding Deposit, Credit and Collection)
- Customer Satisfaction Index (CSI with *q weighted average*)

3. Safety

- OHSA Recordable Incident Rate = $\dfrac{\#\text{ of Recordable Cases}}{200{,}000\text{ Work Hours}}$

- Accident Severity Rate = $\dfrac{\text{\# of Days away from work + Restricted Activities}}{\text{200,000 Work Hours}}$

- Preventable Vehicle Accidents = $\dfrac{\text{\# of Reportable Accidents} \times 1{,}000{,}000}{\text{Miles Driven (mile)}}$

Utility 3.

3-A. Measurement Areas:

1. Customer Service

- Customer Satisfaction Survey (Commercial, Government and Public Stakeholders)

2. Employee (Safety and Satisfaction)

- Lost Time Accidents (Employees and Contractors in accordance with WCB Act)
- Employment Engagement Index – ACRM (Alignment, Capability, Resources, Motivation)

3. Environment

- Reportable Environmental Incidents
- % of Environmental Management System Activities completed
- Environmental Incidents – Reportable or not

4. Financial

- $\dfrac{\text{OMA (in Cents)} \quad \text{(Transmission Operations and Maintenance Expenditures)}}{\text{GWh} \quad \text{(Domestic Energy Volume delivered by BC Hydro)} \quad \times \quad \text{Circuit kilometers of TS}}$

5. Human Resources

- Attrition Rate (%) – Voluntary Attrition and Retirements of Regular Employees

6. Market Access

- Inter-tie Congestion (% of Total Hours in a month): 4 Inter-tie Paths (Imports and Exports from and to US and Alberta)

7. Reliability

- SAIDI = Planned + Unplanned Outages (NOT interruptions due to outages attributed to generators)

8. Safety

- % of Safety Management System Activities completed
- Contractor, Control Centre and Public Accidents: Information metric to ELT

Utility 4.

4-A. Measurement Areas:

1. Financial

- $$\frac{\text{Net Profit (Excluding incidental items)} + \text{Depreciation/Amortization}}{\text{Net Debt}}$$
- $$\frac{\text{Net Profit} + \text{Depreciation/Amortization} + \text{Net Financial Income and Expense}}{\text{Net Financial Income and Expense}}$$
- A sound A rating profile
- A minimum solvency ratio on the basis of IFRS principles

2. Reliability

- CAIDI for LV, MV and HV: where the number of clients per interruption are counted based on the average number of clients per MV/LV transformer in the major postal area
- CAIDI for gas
- Number of Customers (i.e. minor postal areas) with 6 or more interruptions per year
- CML = # of Customers x Total Restoration Time (in minutes)
- CAIDA: the total amount of CML for all incidents per year (or per month or per area or per voltage level or per last 12 months) divided by the total number of customers and the time period considered in minutes
- Reporting is controlled by the Regulator, as penalties to be paid to customers as well as penalty in the tariff-structure are depending on the reported results.
- Planned Unavailability & Unplanned Unavailability

3. Customer

- Customer Satisfaction Survey (conducted by an external party for random clients)

4. Employee

- Number of serious incidents
- Employee involvement survey
- Average percentage of ill employees
- Lost time injuries are counted and reported as a total figure as well as a top ten list

5. Other

- Percentage of work performed (in financial terms, but also as length of cables, number of new connections, number of renewed connections, number of km run with gas leakage detection, percentiles of time to arrival at location in case of interruptions, etc.)
- Percentage of new and updated connections within required period
- Percentage of earnings in relation to the financial claims put forward by Utility

- Major projects: monthly status reports

Utility 5.

5-A. Measurement Areas:

1. **Customer Service**
2. **Employee**
    - Employee Survey Index
    - Safety Index
    - Lost Time Injuries: # of Injuries causing employee to off-work
    - Sick Leave: Annualized Average Sick Day per Employee
    - Training: Annualized Training Days per Employee
    - Employee Numbers: Total # of Employees
3. **Financial**
    - ROE (Return on Equity)
    - Net Profit Before Tax
4. **Other**
    - Total Capital Expenditure
    - Average Sale Price
    - Market Share
    - Sales
    - Net Frequency Control Ancillary Service Revenue
    - Sent-out Production, Coal Cost, Thermal Efficiency, Environment License Non-Comply, Operating Expenditure
    - Innovation
    - Green Energy Production
5. **Reliability**
    - Interruptions (same as North American Electric Reliability Corporation, NERC)

Utility 6.

6-A. Measurement Areas:

1. **Customer Service**
    - Customer Satisfaction Survey of Transmission & Generator Customers

2. Employee

- Safety and Risk Assurance Measures (Fatalities, Severity Rate, Lost Time Incident Rate (LTIR), Total Recordable Incident Rate (TRIR), Disabling Injury Incidence Rate (DIIR), Leadership Inspections)
- LTIR = $\dfrac{\text{Number of Lost Time Incidents} * 200\,000}{\text{Number of Working Hours}}$
- TRIR = $\dfrac{\text{Number of total recordable incidents} * 200\,000}{\text{Number of working hours}}$
- DIIR = $\dfrac{\text{Number of disabling injuries} * 200\,000}{\text{Total number of employee man - hours of exposure}}$
- Human Resources Measures (Transmission People Development Strategies/Initiatives, Transmission Succession Management, Staff Retention Initiatives/Strategy, Human Resources Sustainability Index, Racial Equity, Gender Equity, Disability)

3. Financial

- Net Income (PBIT) = Revenue – Operating Expenditures – Corporate Overheads
- Operating Expenditure (OPEX)
- Capital Expenditure (CAPEX)
- Accuracy of Projections – Half Year: The full year OPEX forecast made at half-year is not expected to deviate by more than 1% from the actual OPEX spent by full year.
- Cash Flow Forecasting Accuracy: Tx's cash requirements as submitted to Treasury are not expected to deviate by more than 4%

4. Reliability

- Interruption Performance Measures (System Minutes Lost, Number of Major Events, Number of Supply Interruption Events, SARI)
- System Availability Measures (Composite Circuit Availability, Unplanned Circuit Unavailability)
- Equipment Reliability Measures (Plant Health Index)
- Power Quality Performance Measures (Voltage Magnitude/Regulation, Voltage Unbalance, Total Harmonic Distortion (THD))
- Disturbance Measures (Number of Line Faults)
- Load Forecasting Measures (Absolute Percentage Error in Hourly Forecasting, Peak Hour Absolute Percentage Error, Number of Daily Forecast Errors)
- System Minutes Lost = $\dfrac{\text{Load Interruption (MW)} \times \text{Duration (Minutes)}}{\text{Utility Annual System Peak}}$
- Utility System Peak = Utility Generation + Imported Power (International) – Exported Power (International)

- $\text{SARI} = \frac{\sum \text{Individual Sustained Supply Point Interruption Duration (Minutes)}}{\text{\# of Individual Sustained Supply Point Interruption}}$
- $\text{Availability of Bays} = \frac{\text{Time Period} - \text{Total Duration Bay Unavailable in Time Period}}{\text{Time Period} * \text{Number of Bays}}$

5. Social and Environmental

- Social (BEE; Black Economic Empowerment, BWO; Black Woman's Organization)
- Environmental (Conformance to ISO14001, Number of Legal Contravention)

Utility 7.

7-A. Measurement Areas:

1. Financial

- Net Income
- Operating Expenses
- Capital Expenditures
- Net Operating Income

2. Reliability

- Frequency of Delivery Point Interruptions (115kV or above)
- Duration of Delivery Point Interruptions (115kV or above)
- Unsupplied Energy

3. Customer

- Annual Customer Meetings and Presentations; Tx and Generator Customers (Topics: *Reliability, Communications, Relationships, Responsiveness, Outage Scheduling*)

4. Employee

- High Risk Incidents: High Maximum Reasonable Potential for Harm (MRPH);
- Lost Time Injuries: *Direct Employees* ONLY (NO contracted workers)
- Accident Severity Rate (ASR): *Direct Employees* ONLY (NO contracted workers)

$$\frac{\text{Total \# of Days Lost or Charged for all disabling injuries} \times 200{,}000}{\text{Total \# of Hours worked by employees}}$$

- Loss Time Injury Frequency Rate: *Direct Employees* ONLY (NO contracted workers)

$$\frac{\text{\# Incidents of Fatalities} + \text{Permanent Total Disabilities} + \text{Permanent Partial Disabilities} + \text{Temporary Total Disabilities} + \text{Medical Attention}}{200{,}000\,\text{Hours Worked}}$$

5. Other

- Net Operating Income

Utility 8.

8-A. Measurement Areas:

1. Business

a. Work Program Accomplishment

b. Major Project Status

2. Customer Service

c. Customer Satisfaction Survey of Tx Customers

d. Customer Satisfaction Survey of Generator Customers

3. Employee

a. Serious Incidents: *electrical incidents*, *preventable motor vehicle accidents*, f*alls from a different level*, *objects dropped*, *work equipment related* and *asset equipment failure related.*

b. Serious Lost Time Injuries: *Direct Employees* ONLY (NO contracted workers)

c. Accident Severity Rate (ASR): *Direct Employees* ONLY (NO contracted workers)

$$\frac{\text{Total \# of Days Lost or Charged for all disabling injuries} \times 200{,}000}{\text{Total \# of Hours worked by employees}}$$

d. Lost Time Injury Frequency Rate: *Direct Employees* ONLY (NO contracted workers)

$$\frac{\text{\# Incidents of Fatalities} + \text{Permanent Total Disabilities} + \text{Permanent Partial Disabilities} + \text{Temporary Total Disabilities} + \text{Medical Attention}}{\text{200,000 Hours Worked}}$$

4. Financial

a. Net Income after Tax

b. Credit Rating

5. Reliability

a. Frequency of Delivery Point Interruptions

b. Duration of Delivery Point Interruptions

c. Unsupplied Energy

d. Unavailability

Utility 9.

9-A. Measurement Areas:

1. Customer (covering Reliability and Customer)

- Transmission Continuity Index (NOT same as SAIDI or SAIFI; Internal Measure): an indicator of customer reliability related to interruptions; $\frac{\sum_{i}^{n}(Ci \times Hi)}{Ct}$

  where, Ci is the total number of Ts and Ds customers affected by the Interruption "i" which has been caused by the Transmission network, Hi is the duration of Sustained Interruptions (caused by either planned or forced outages) experienced at the customer measured in hours, Ct is the total number of customers supplied by Utility

- NERC/NPCC Compliance (Non-accordance Rates to the requirements of NERC/NPCC)
- Number of yearly accidental spills declared to the authorities: All accidental spills impacting the environment must be declared by the appropriate provincial ministry of regardless of the amount except for halocarbon for which minimal quantities are defined according to related Articles
- Percentage of litres recuperated yearly from accidental spills declared to the authorities:

$$\frac{\text{Number of recuperated litre declared to the authorities} \times 100}{\text{Number of spilled litres declared to the authorities}}$$

2. Employee

- Loss Time Injury Frequency Rate:

$$\frac{\text{Frequency Rates of Accidents with Time Loss and Medical Assistance}}{\text{200,000 Hours Worked}}$$

3. Other

- Work Accomplishments
- Major Project Status
- Measures requested by the Province of Quebec's regulator

4. Shareholders (Financial)

- Benefits of Transmission Division: Benefits tied to the Transmission network activities (CAD $ in millions)
- Efficiency (in terms of planned network capacity): Opex = All Indirect and Direct Cost – Amount Charged to Investment and Activity Charge to other divisions

Utility 10.

10-A. Measurement Areas:

1. Customer Service

- Customer Satisfaction Survey hosted by Government
- Customer Satisfaction Survey hosted by KEPCO for 66 kV and above

2. Employee

- Frequency Rate of Injury = (Injury Incidents x 10^6)/(Annual Labour Time)
- Severity Rate of Injury = (Total lost days x 10^3)/(Annual Labour Time)
- Frequency Severity Index =

$$\sqrt{(\text{Frequency Rate of Injury} \times \text{Severity Rate of Injury})}$$

3. Financial

- EVA (Economic Value Added): Net Operating Profit After Tax – Capital Expenses (Operating Income = Operating Revenue – Operating Expenses)
- Operating Income

4. Other

- Labour Productivity = $\frac{\text{Public Profit}}{\text{Average Manpower}}$
- Load Factor = $\frac{\text{Average Power}}{\text{Maximum Power}}$
- Average Power = $\frac{\text{The gross annual generated power}}{8{,}760\text{ hrs}}$
- Maximum Power is the maximum power loaded during one hour in a year

5. Reliability

- SAIFI = $\frac{\sum Ni}{Nt} = \frac{CI}{Nt}$ (Ni: Number of Interrupted Customers for each Sustained Interruption event during the Reporting Period; Nt: Total Number of Customers Served for the Areas)
- SAIDI = $\frac{\sum ri\,Ni}{Nt} = \frac{CMI}{Nt}$ (ri: Restoration Time for each Interruption Event; CMI: Customer Minutes Interrupted; Ni: Number of Interrupted Customers for each Sustained Interruption event during the Reporting Period; Nt: Total Number of Customers served for the Areas)
- Regulated Voltage Maintenance Ratio = $\frac{A \times 100\%}{B}$ (A: Total Number of Place supplied with regulated voltage during 24 hours; B: Total Number of Place measured; Korean Standard low voltage is 220 $\pm$ 13 [V])

Utility 11.

11-A. Measurement Areas:

1. Aboriginal Peoples

- Percentage of impacted Aboriginal communities with a workable management framework
- Percentage Aboriginal employment (Corporate overall, Management, Professional, Northern)

2. Corporate Citizenship

- CEA Public Attitude Index
- Utility Corporate Citizenship Index

3. Customer Service

- Retail rates: electricity
- Retail distribution rates: natural gas
- System average interruption duration
- System average interruption frequency
- CEA Customer Service Index
- Public contact – natural gas and electric
- Natural gas market share

4. Employee

- Percentage of non-entry (NEL) positions filled by external applicants =

$$\frac{\text{NEL positions filled externally}}{\text{Total NEL positions filled}}$$

- Percentage of designated group members in Utility workforce (Women, Women in Management, Women professionals, Persons with disabilities, Visible minorities)

5. Environment

- Environmental component of CEA Customer Service Index
- Corporate citizenship index
- Net greenhouse gas emissions (overall, electricity generation, natural gas operations, fleet, buildings (natural gas & electricity), diesel generation and SF6

6. Financial

- Interest Coverage = Net Income + Interest on Debt
- Debt/Equity Ratio = $\frac{\text{Total Debt}}{\text{Total Debt} + \text{Total Equity}}$
- Capital Financing Ratio = $\frac{\text{Internally Generated Funds}}{\text{Net Capital Construction Expenditures}}$ (where, Internally Generated Funds = Cash provided from operating activities; Net Capital Construction Expenditures = Additions to capital assets net of contributions in aid of construction – Net Expenditures for major new generation and transmission + Miscellaneous Project expenditures)
- Cost per customer OM&A – electric & gas =

$$\frac{\text{Operating, Maintenance, and Administrative Expenses (electric/gas operations)}}{\text{Total Customers (electric/gas operations)}}$$

- Net export revenue as a percentage of total electric revenue

7. Safety

- High Risk Accidents
- Accident Severity Rate
- Accident Frequency Rate = $\frac{\text{Number of Lost Time Injuries} \times 200{,}000}{\text{Hours Worked}}$

8. Reliability

- Outage Time = $\frac{\text{Total customer} - \text{minutes of interruption per year}}{\text{Total customers served}}$
- Outage Frequency = $\frac{\text{Total customer} - \text{interruptions}}{\text{Total customers served}}$ (NOTE: Currently Manitoba Hydro records only interruptions of duration greater than one minute)
- NOTE: Service Quality = Service Reliability (the continuity of supply) + Power Quality (pre-defined regularity standards)

Utility 12.

12-A. Measurement Areas:

1. Reliability

- Average Annual Availability = $\frac{(1 \; - \; \text{Total Hours of Circuit Unavailability}) \; \times \; 100}{\text{Hours per year} \times \text{Total Numbr of circuits}}$
- Unsupplied Energy = MW at time of loss x Duration of loss (Mins)/60 = MWh
- Short Term Planning Churn
- Planned Unavailability = $\frac{\text{Total Hours of Circuit Planned Unavailability}}{\text{Hours per year} \times \text{Total number of circuits}}$
- Unplanned Unavailability = $\frac{\text{Total Hours of Circuit Unplanned Unavailability}}{\text{Hours per year} \times \text{Total number of circuits}}$

2. Efficiency and Financial

- Controllable Costs: to identify how well controllable costs are forecasted to outturn compared to the budget figure
- Operating Profit (EBIT, Earnings before Interest and Tax)
- Cash flow: Target based on UK operating profit plus non cash items and zero working capital movements excludes capital related movements (e.g. capital contribution) but allows for structural movements
- Capital Expenditure
- Incentive Scheme Performance

3. Other (SHES – Safety, Health, Environment and Security)

- SF_6 Leakage
- Cable Oil Leakage
- Near miss or hazards to injury ratio
- Category 1 Environmental Incidents
- Greenhouse Gas emissions

4. Employee

- Work Related Lost Time Injuries
- Injury Frequency Rate = $\frac{\text{Injuries resulting in employees taking time off work}}{\text{100,000 Hours worked}}$

5. Regulatory/Customer

- Process compliance and improvement: National Grid is required to report to OFGEM (the Office of Gas and Electricity Markets, UK Government) any frequency deviation outside of statutory limits (49.5 - 50.5 Hz)
- The Electricity Safety, Quality and Continuity Regulations permit variations in voltage not exceeding 6% at voltage below 132 kV and not exceeding 10% at voltages of 132 kV or above
- Power Quality

Utility 13

13-A. Measurement Areas:

1. Customer Service

- Customer Satisfaction Index (Residential and Commercial): Customer ratings of importance and satisfaction on 16 applicable service attributes

2. Employee

- Near Miss Reports: Cumulative number of near miss incidents reported vs. target
- Disabling and Medical Aid Injuries: Cumulative number of disabling and medical aid injuries to date vs. target = $\frac{\text{All disabling and medical aid injuries}}{\text{Hours worked} \times 100 \text{ Employees}}$
- Disabling Injuries

3. Environment

- ISO Exceptions/Observation = $\frac{\text{The Number of ISO Exceptions/Observations}}{\text{The Number of ISO Audits}}$ (NOTE: Five observations of non-conformance with an internal standard equates to one exception that is taken a finding of non-conformance with the ISO 14001 Standard

- Hydraulic Conversion Factor: Efficiency in converting water to energy =

$$\frac{\text{Net GWh}}{\text{Million Cubic Metres of Water Consumed}}$$

- Thermal Emissions per MWh =

$$\frac{\text{Mass of sulphur dioxide (SO2) released to atomsphere from heavy fuel oil thermal plant}}{\text{Net Energy generated from thermal plant}}$$

- Thermal Conversion Factor = $\frac{\text{Net KWh}}{\text{Barrels of Heavy Fuel Oil Consumed}}$

4. Financial

- Controllable Unit Costs – Corporate Overall =

$$\frac{\text{Corporate controllable operating costs (operating expenses} - \text{fuel} - \text{purchased power} - \text{capital related expenses)}}{\text{Total Energy Delivered to Customers}}$$

- Controllable Unit Costs – Generation =

$$\frac{\text{Generation controllable operating costs (operating expenses} - \text{fuel} - \text{purchased power} - \text{capital related expenses)}}{\text{Installed MW + Net Generation}}$$

- Controllable Unit Costs – Transmission =

$$\frac{\text{Transmission controllable operating costs (operating expenses} - \text{fuel} - \text{purchased power} - \text{capital related expenses)}}{\text{230 kV Equivalent Circuit Km}}$$

- Controllable Unit Costs – Distribution =

$$\frac{\text{Distribution controllable operating costs (operating expenses} - \text{fuel} - \text{purchased power} - \text{capital related expenses)}}{\text{Circuit Km Km}}$$

- Controllable Cost Budget Performance: Cumulative tracking of controllable cost budget versus actual expense

5. Other

6. Reliability

- Generation (Weighted Capability Factor: Year round availability of generating plant, DAFOR, Unsupplied Energy)
- Transmission (SAIDI, SAIFI, SARI)
- Distribution (SAIDI, SAIFI)
- Other (Under Frequency Load Shedding)
- Weighted Capability Factor: Measures the percentage of the time that a units or group of units are available to supply some or all load. The larger the unit (measured by its Maximum Continuous Rating or MCR), the greater its contribution towards the overall total → Year-round availability of generating plants & Winter availability of generating plants
- Weighted DAFOR: Measures the percentage of the time that a unit or group of units are unable to generate at its Maximum Continuous Rating (MCR) due to forced outages

- Unsupplied Energy: MW-Min
- Transmission SAIFI & SAIDI: per delivery point
- Transmission SARI: per interruption
- Distribution SAIFI: per customer
- Distribution SAIDI: per customer
- Under Frequency Load Shedding: Customer load interruptions due to a generator trip

Utility 14.

14-A. Measurement Areas:

1. Employee

- Employee Development = $\dfrac{\text{Number of Days of further training}}{\text{Number of Employees}}$

2. Financial

- Total Costs = Total Current Operating Costs + Fixed Costs + Taxes

3. Other

- Total Number of Switching Programs (50 kV – 400 kV): Difference between programmed and actual energy exchange from and to the control area

4. Reliability

- Number of Interferences (50 – 400 kV): Total Number of Momentary and Sustained Interferences with no effect on energy supply
- Unsupplied Energy: Number, Duration and Unsupplied Energy of Delivery Point Interruptions (per interruption for both Momentary and Sustained Interruptions experienced at Delivery Point)

Utility 15.

15-A. Measurement Areas:

1. Other

- Percent of Planned Maintenance Achieved

2. Reliability

- Number of Unsupplied Energy Interruptions caused by Transgrid (Two Measures):
  (a) $0.05 <$ Number of events with loss of supply ≤ 0.4 System Minutes

(b) Number of events with loss of supply > 0.4 System Minutes

- Average Duration (in minutes) of Unplanned Outages
  - (a) Transmission Line Availability (%)
  - (b) Transformer Availability (%)
  - (c) Reactive Plant Availability (%)

Utility 16.

16-A. Measurement Areas:

1. Financial

- Regulatory Income = WACC (Weighted Average Cost of Capital) x RAB (Regulatory Asset Base)
- Income before and after tax
- Credit Rating
- IFRS (International Financial Reporting Standards) and Regulatory Rules

2. Reliability

- # of Incidents per year for 220 kV and 380kV grid: Number of non planned situations of reduction of available connections to the connected party per year (reduced redundancy of the connection)
- # of outages resulting in not supplied energy & outage time for 150kV grid: Number if outages leading to reduction or loss of supplied energy to the connected party and duration thereof
- Deviation from agreed capacity with neighbouring TSO's: *Megawatt x Time* → Unsupplied Energy (+/-)

3. Employee

- Illness leave (short term): % of employee time
- Employee satisfaction survey: two-year score held by an external consultant; trend analyses
- Number of accidents and incidents: Accidents (unwanted occurrence on Utility premises, caused by unsafe action or unsafe situation with the consequence of harm to persons or damages to the installations), Incidents (unwanted occurrence on Utility premises, caused by unsafe action or unsafe situation with the potential consequence of harm to persons or damage to the installations)
- Company medical care survey: feedback to manager from points raised by medical officer

4. Others

- Project Realization: projects finished as projected and mainly time (projects are normally released based on detailed cost calculation)

Utility 17.

17-A Measurement Areas:

1. Customer (covering Reliability and Customer)

- **Average Interruption Time (AIT)** = $\frac{\sum_{i}^{Nbi}(EENS - SI)}{YEC} x8760x60$ **mins**

where (EENS – SI) is the Estimated Energy Not Supplied for each Sustained Interruption (in MWh), YEC is the total Energy Consumption in the system over a one year period (in MWh), NbI is the total number of incidents affecting customers at the end of the reporting period. This indicator includes only forced interruptions and not planned interruptions.

- **Average Interruption Duration (AID)** = $\frac{\sum_{yearN}(TxPNS)}{PNS}$

where T is the duration of each sustained interruption (in mn) and PNS is the interrupted power (in MW).

- **Average Interruption Frequency (AIF)** = $\frac{AIT}{AID}$

AIF is measured in interruption per year.

2. Reliability

- Transmission System Availability captures the impact of all outages on transmission lines and on transformers.

  Grid availability = 100% - outage (%)

$$\text{Outage} = \left(\frac{\sum_{i=1}^{N}(F_i + P_i)}{8760xN} \right) x100\%$$

where F_i is the annual forced outage duration in hours for transmission line circuit and transformer, P_i is the annual planned outage duration in hours for transmission line circuit and transformer, N is the total number of declared in-service transmission line circuits + transformers whereas 8760 is the number of hours per year.

Utility 18.

18-A Measurement Area:

1. **Business**
   - Work Program Accomplishment
   - Annual goals fulfillment
2. **Customer Service**
   - Customer Satisfaction Survey of Dx Customers
   - Customer Satisfaction Survey of Industrial connected Customers and Generators.
3. **Employee**
   - Serious Incidents: *electrical incidents*, *preventable motor vehicle accidents*, and falls *from a different level*, *objects dropped*, *work equipment related* and *asset equipment failure related*
   - Serious Lost Time: *Direct Employees* ONLY (NO contracted workers)
4. **Financial**
   - EBITDA: Earnings before Interests, Taxes, Depreciation and Amortization
   - OPERATING CASH: Cash generated before interests
5. **Reliability**
   - Transformers reliability

$$CONFT = \frac{HC - \sum_{n=1}^{j} H_{ifj}}{NE * HC} * 100$$

where HC is annual hour's calendar, H_{ifj} is the hours of unavailability forced of the j transformer and NE is the number of transformers considered.

- Lines reliability

$$CONFL = \left\{ \frac{\sum_{j=1}^{N} \left(\left(HC - H_{ifj} \right) * L_j \right)}{HC * \sum_{j=1}^{N} L_j} \right\} * 100$$

where HC is the annual hour's calendar, H_{ifj} is the hours of unavailability forced of the j line and L_j is the length of the j line.

- Transformers availability

$$DISPT = \frac{HC - \sum_{n=1}^{j} (H_{ifj} + H_{impj})}{NE * HC} * 100$$

where HC is the annual hour's calendar, H_{imp} is the hours of programmed unavailability of the j transformer, H_{ifj} is the hours of forced unavailability of the j transformer and NE is the number of transformers considered.

- Lines availability

$$DISPL = \left\{ \frac{\sum_{j=1}^{N} \left(\left(HC - H_{ifj} - H_{impj} \right) * L_j \right)}{HC * \sum_{j=1}^{N} L_j} \right\} * 100$$

Where HC is the aannual hour's calendar, H_{ifj} is the hours of programmed unavailability of the j line, H_{impj} is the hours of forced unavailability of the j line and L_j is the length of the j line.

- Lines outages indicator
- Forced unavailability's Lines
- Disconnection of Transformers
- Effectiveness of Protection
- Effectiveness of Switches
- Not provided energy
- Equivalent duration of interruption
- Equivalent frequency of interruption
- Average time of Line Repair
- Average time among flaws of lines
- Technical productivity of the manpower of Maintenance of TTSS
- Benchmarking

Utility 19.

19-A Measurement Areas:

1. Power System Reliability

- Number of Significant System Events
- Mechanical security rate of Sub-stations (rate of substations the electric supply of which is robust against weather hazards)

2. Quality of Supply

- Frequency of Short Cuts

- Frequency of Long Cuts
- Equivalent Interruption Time
- Unsupplied Energy
- Unplanned unavailability
- Vulnerability ratio

3. Financial

- Net sales
- Earnings before interest, taxes, depreciation and amortization (EBITDA)
- Net income after tax
- Cash flow
- Capital Expenditures
- Operating Expenditures
- Net debt
- Return on capital employed (ROCE)
- Return on equity (ROE)
- Gearing

4. Safety of the staff

- Number of industrial accidents leading to lost workdays
- Number of industrial accidents
- Accident frequency leading to lost workdays per million work hours
- Accident frequency per million work hours
- Severity rate of industrial accidents

5. Employee

- Number of employees
- Number of employees by age range and by degree category
- Annualized training hours
- Number of employees, who have benefited from training hours
- External employees' mobility: recruitments and leavings

6. Customer

- Rate of fulfilment of contractual agreements regarding quality of supply
- Fulfilment of contractual agreements regarding electricity producers
- Fulfilment of commitments related to connections to network (cost and timing)
- Wrong invoices rate
- Customer satisfaction survey: level of customers satisfied or very satisfied and level of customers very satisfied.

7. Environment

- Rate of underground cables
- Rate of existing overhead network removal
- Total length of overhead network
- SF6 leakage
- Transformers and underground cables oil spillage

Appendix D

Outline of Measure Definitions

Appendix D

Outline of Measure Definitions

Table D1
FINANCE / BUSINESS

Corporate Level Measures	Definition
Capital Variance	Capital Budget versus Actual Expenditures
O&M Variance	O&M Budget versus Actual Expenditures
Regulatory Process	Successful conclusion of rate cases involving state and federal commissions
OMA (Cents) / GWh-km	OMA - Transmission Operations and Maintenance expenditures. GWh - Domestic Energy Volume delivered by the Utility. Kilometres - Circuit kilometres of transmission lines
Credit Rating	- follows regulatory rules; - meets IFRS rules
Net Income after tax	Net income after tax is defined as revenue less total current operating and fixed costs, including taxes
income before and after tax	- follows regulatory rules; -meets IFRS rules
regulatory income (=WACC x RAB)	- follows regulatory rules-meets IFRS rules
EVA (Economic value added)	EVA is Net value increment created by the operating activities of the business. It is defined as net operating profit after tax minus capital expenses, income which stockholders expect.
Operating Income	Operating Income is defined as operating revenue minus operating expenses. Operating income ratio (this indicates profitability) is defined as operating income divided by operating revenue.
Capital Financing ratio	Calculation: Capital Financing Ratio = Internally Generated Funds/Net Capital Construction Expenditures. Internally Generated Funds = Cash provided from operating activities. Net Capital Construction Expenditures = Additions to capital assets net of contributions in aid of construction - Net Expenditures for major new generation and transmission facilities + Miscellaneous Project expenditures (i.e. North Central). Measure Rationale: This is a financial strength measure that determines the extent to which the utility operating activities provide funds to finance capital construction expenditures. Data Collection: Utility monthly Management Reports publish a 12-month rolling average value for this measure.
Cost per customer OM&A - electric	Calculation: OM &A cost per customer = (Operating, Maintenance and Administrative Expenses (electric/gas operations))/Total Customers (electric/gas operations). Operating, Maintenance and Administrative Expenses = Cost of Operations - Capitalized Overhead.

	"Total customers" for electric operations excludes export customers and "no-worry" water tank lease customers. "Total customers" for gas operations includes active gas customers taking delivery of natural gas on the distribution system (includes T-customers and Western Transportation Service customers). Measure Rationale: This is a financial strength measure that determines the ability of management to control operating costs incurred in the delivery of electricity and natural gas to Utility and Gas customers. Data Collection: Utility monthly Management Reports publish a monthly, year-to-date, value for these measures.
Cost per customer OM&A - gas	Calculation: OM&A cost per customer = (Operating, Maintenance and Administrative Expenses (electric/gas operations))/Total Customers (electric/gas operations). Operating, Maintenance and Administrative Expenses = Cost of Operations - Capitalized Overhead. "Total customers" for electric operations excludes export customers and "no-worry" water tank lease customers. "Total customers" for gas operations includes active gas customers taking delivery of natural gas on the distribution system (includes T-customers and Western Transportation Service customers). Measure Rationale: This is a financial strength measure that determines the ability of management to control operating costs incurred in the delivery of electricity and natural gas to Utility customers. Data Collection: Utility monthly Management Reports publish a monthly, year-to-date, value for these measures.
Debt/Equity ratio	Calculation: Debt to Equity Ratio = Total Debt/ (Total Debt + Total Equity). Total Debt = long term debt + current portion of long term debt + notes payable - temporary investments - sinking fund investments. Total Equity = retained earnings + contributions in aid of construction. Measure Rationale: This financial strength measure determines the relative percentage of assets financed through debt versus equity. The debt to equity ratio communicates the Utilities ability to withstand financial risks (i.e., drought, physical property risks, etc.) and to issue new debt in order to fund major capital projects. Data Collection: Utility monthly Management Reports publish a fiscal year-to-date, value for this measure.
Interest Coverage	Calculation: Interest Coverage = (Net Income +

	Interest on Debt)/Interest on Debt. Measure Rationale: It is a financial strength measure that determines the extent to which net income is sufficient to pay gross interest on debt. Data Collection: Utility monthly Management Reports publish a 12-month rolling average value for this measure.
Net export revenue as a percentage of total electric revenue	
Controllable Cost Budget Performance	Cumulative tracking of controllable cost budget versus actual expense where controllable cost is operating expenses less fuel, purchased power and capital related expenses.
Controllable Unit Costs - Corporate Overall	Corporate controllable operating costs (operating expenses less fuel, purchased power and capital related expenses) DIVIDED by total energy delivered to customers.
Controllable Unit Costs - Distribution	Distribution controllable operating costs (operating expenses less fuel, purchased power and capital related expenses) DIVIDED by Circuit Km.
Controllable Unit Costs - Generation	Generation controllable operating costs (operating expenses less fuel, purchased power and capital related expenses) DIVIDED by 1) Installed MW, and 2) Net generation.
Controllable Unit Costs - Transmission	Transmission controllable operating costs (operating expenses less fuel, purchased power and capital related expenses) DIVIDED by 230 kV Equivalent Circuit Km.
Accuracy of Projections - Half year	Accuracy of Projections - Half year. The full year OPEX forecast made at half-year is not expected to deviate by more than 1% from the actual OPEX spent by full year.
Capital Expenditure (CAPEX)	Capital Expenditure (CAPEX) CAPEX is defined as all the funds used by Transmission to build or upgrade our physical assets, including lines, lands & rights, production equipment etc.
Cash Flow Forecasting Accuracy	Cash Flow Forecasting Accuracy: Transmission's cash requirements as submitted to Treasury are not expected to deviate by more than 4%
Net Income (PBIT)	Net Income (PBIT): Indicates the profit before interest and finance charges and it measures Revenue less (operating expenditure + corporate overheads).
Operating Expenditure (OPEX)	Operating Expenditure (OPEX): OPEX is defined as all the costs incurred in carrying out transmission business such as manpower costs, depreciation, maintenance etc.
Net Profit Before Tax	Total revenue less total cost excluding tax.
Return On Equity	Net profit after tax divided by total equity.

Capital Expenditures	
Net Income	
Operating Expenses	
Capital Cost Management	Capital Cost Management - The intent of this goal is to provide incentives for the organization to effectively manage actual capital project costs to approved project estimates, focusing results on solid estimating and cost mgmt during project execution. Cost reduction remains a focus for the organization and is accommodated by providing for the ability to reduce the Control Estimate through a scope change. *Direct Assign Projects: The Control cost budget estimate for direct assign projects will be based on the cost estimate included in the revised Permit and License (P&L) application that is up to 180 days after receipt of the P&L Application. In accordance with the System Operators Direct Assign Rules the revised P&L application is generally considered accurate within +10%/-10% *Capital Upgrade and Replacement Programs: The Control Estimate for capital upgrade and replacement programs will be as per the GTA.
Net Income After Tax	Net Income is based upon the audited financial statements in accordance with CICA Generally Accepted Accounting Principles for the year end.
Total Costs	Total current operating and fixed costs, including taxes.

Table D2
SAFETY

Corporate Level Measures	Definition
OSHA Recordable Incident Rate	The number of recordable, (includes fatal, restricted, lost work day and medical), cases per 200,000 work hours.
OSHA Severity Rate	The number days away from work and restricted activity days per 200,000 work hours.
Preventable Vehicle Accident Frequency Rate	The number of reportable vehicle accidents x 1,000,000 divided by the miles driven.
% of Safety Management System activities completed	As part of the Safety Management System (SMS), an annual plan of safety activities is submitted to the Executive Leadership Team (ELT). Quarterly the progress to the completion of these goals is recorded.
Contractor, control centre and public accidents (includes near misses)	Contractor, control centre and public incidents are reported as an informational metric to the ELT. This information includes "near miss" information as a narrative but is not included towards our corporate goal.
Accident frequency rate	Calculation: (Number of Lost Time Injuries x 200,000)/Exposure Hours (Hours Worked). A lost-

	time injury is an injury/illness resulting in Lost Days beyond the date of injury as a direct result of an Occupational Injury/Illness incident. A Fatality is not considered a Lost-Time injury. Measure Rationale: The Accident Frequency Rate reflects the frequency of injuries based on the total number of workplace lost-time injuries or illnesses which occurred in the specified period (e.g., fiscal year). Data Collection: Safety performance reports are available on Safety Net, located on the Employee Safety & Health website accessible through MPower. Monthly hours worked and accident data may not be available until the middle of the following month. For example, if you need the report to include hours and accidents ending the month of May you should wait until June 15th to run the report. Safety Net data is not static; the reports will always reflect current information. If you are comparing reports run at different times for the same selected period, the report data may be different. This may occur if an accident that happened within the selected period had been added to the database or if an estimated days-lost accident has been updated since the first report was run. For Safety Net User Tips and Definitions, select the quick link called Safety on MPower; this takes you to the Employee Safety & Health (ESH) website. Select SafetyNet, then SafetyNet Tips.
Accident Severity rate	Calculation: (Number of Lost Days x 200,000)/Exposure Hours (Hours Worked). The number of Lost Days represents calendar days that the employee is unable to work beyond the day of injury/illness. A lost-time injury is an injury/illness resulting in Lost Days beyond the date of injury as a direct result of an Occupational Injury/Illness incident. A fatality is not considered a Lost-Time Injury. Calendar days lost are used in the calculation rather than working days lost, to ensure consistency of reporting. Use of calendar days prevents reporting inconsistencies that arise when reporting days lost for a person who works 7.92 hours per day and a five day week vs. days lost for a person who works 10 hours per day for six days in the week. The days lost calculation is based on the number of days lost assigned to accidents that have occurred within the selected report period. Days lost are estimated if the employee has not yet returned to work. Days lost are estimated from the start compensation date to the selected end date of the report. Measure Rationale: The accident severity rate reflects the seriousness of workplace injuries. Data Collection: Safety performance reports are available on SafetyNet, located on the Employee Safety & Health website accessible

	through MPower. Monthly hours worked and accident data may not be available until the middle of the following month. For example, if you need the report to include hours and accidents ending the month of May you should wait until June 15th to run the report. SafetyNet data is not static; the reports will always reflect current information. If you are comparing reports run at different times for the same selected period, the report data may be different. This may occur if an accident that happened within the selected period had been added to the database or if an estimated days-lost accident has been updated since the first report was run.
High risk accidents	Calculation: Count of high-risk accidents. High-risk accidents include all reported injuries as the result of electrical contacts, falls from heights greater than 2.5 meters, and to motor vehicle accidents. Measure Rationale: High-risk accidents represent a grave concern in our safety performance. Each high-risk accident has significant probability of fatality or permanent injury. This target is annually set to zero, and is considered achievable. Data Collection: Safety performance reports are available on SafetyNet, located on the Employee Safety & Health website accessible through MPower. Monthly hours worked and accident data may not be available until the middle of the following month. For example, if you need the report to include hours and accidents ending the month of May you should wait until June 15th to run the report. SafetyNet data is not static; the reports will always reflect current information. If you are comparing reports run at different times for the same selected period, the report data may be different. This may occur if an accident that happened within the selected period had been added to the database or if an estimated days-lost accident has been updated since the first report was run. For SafetyNet User Tips and Definitions, select the quick link called Safety on MPower; this takes you to the Employee Safety & Health (ESH) website. Select SafetyNet, then SafetyNet Tips.

Table D3
RELIABILITY

Corporate Level Measures	Definition
Utility SAIDI - Duration of delivery point outages	The utility defines System Average Interruption Duration Index (SAIDI) as a measure of the reliability of the transmission and SDA system that the utility operates and manages. It includes all planned and unplanned outages, and

	excludes interruption due to outages attributed to generators. It is calculated as the average amount of time in hours across all transmission delivery points that service is interrupted in a year due to planned or unplanned outages.
Duration of Delivery Point Interruptions: a) System all transmission voltages (115kV and above) b) 230kV and above	Duration of Delivery Point Interruptions is an indicator of customer reliability related to the duration of interruptions, that is, the time for which supply of energy is interrupted for customers supplied from the transmission system. This indicator measures the duration of interruptions to customer delivery points. It is expressed mathematically as: Duration of Delivery Point Interruptions = Sum (Di)/N; where: Di is the total effective interruption duration of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over one year period; N is the total number of Delivery Points at year-end of the reporting period. Subset of Duration of Delivery Point Interruptions: Duration of forced sustained delivery point interruptions on 230kv system and above which includes all multi-circuit supplied delivery points.
Frequency of Delivery Point Interruptions: a) System all transmission voltages (115kV and above) b) 230kV and above	Frequency of Delivery Point Interruptions is an indicator of customer reliability related to interruptions, that is, outages on the transmission system that interrupt the supply of energy to transmission customers. This indicator measures the number of interruptions to the supply of power to customer delivery points. It is expressed mathematically as: Frequency of Delivery Point Interruptions = Sum (Mi + Si)/N; where: Mi is the total number of Momentary Interruptions experienced at Delivery Point i over one year period; Si is the total number of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a year period; N is the total number of Delivery Points at the end of the reporting period. This indicator includes all forced and planned interruptions, both momentary and sustained. Subset of Frequency of Delivery Point Interruptions: Frequency of forced, including momentary and sustained delivery point interruptions on 230kv system and above which includes all multi-circuit supplied delivery points.
Transmission System Unavailability	Transmission System Unavailability captures the impact of all outages on transmission lines, not just the outages that interrupt customers. Outages on transmission lines impact both end use customers and energy suppliers by limiting their ability to use the transmission system to its full extent. This indicator is expressed

	mathematically as: Transmission System Unavailability = ((Sum (Fi + Pi)) / (8760 x N)) x 100% Where: Fi is the annual forced outage duration in hours for transmission line circuit i; Pi is the annual planned outage duration in hours for transmission line circuit i; N is the total number of declared in-service transmission line circuits; 8760 is the number of hours per year. This indicator tracks the extent to which the transmission system, including load and generation connection lines and interconnection lines, is not available for use by electricity market participants.
Unsupplied Energy	Unsupplied Energy: The energy that would have been supplied during a forced power interruption. It is calculated by taking the customer load (MW) before the interruption and multiplying it by the time in minutes of the customer load interruption. The units are MW- minutes.
deviation from agreed capacity with neighbouring TSO's	
number of incidents (not resulting in not supplied energy) per year for 220kV and 380kV grid	Utility corporate Level Interruptions definitions: 220/380 kV: number of non planned situations of reduction of available connections to the connected party per year (reduced redundancy of the connection) -150 kV: number if outages leading to reduction or loss of supplied energy to the connected party and duration thereof - deviation from plan: megawatt x time; plus and minus Utility Corporate Level Unsupplied Energy definitions -megawatt x time
number of outages resulting in not supplied energy & outage time for 150 kV grid	Utility corporate Level Interruptions definitions: 220/380 kV: number of non planned situations of reduction of available connections to the connected party per year (reduced redundancy of the connection) -150 kV: number if outages leading to reduction or loss of supplied energy to the connected party and duration thereof- deviation from plan: megawatt x time; plus and minus Utility Corporate Level Unsupplied Energy definitions -megawatt x time

Regulated Voltage Maintenance Ratio	Regulated voltage maintenance ratio is an indicator of customer reliability related to voltage quality. Sample customer is selected in order to measure the status of regulated voltage maintenance during 24 hours. It is expressed mathematically as regulated voltage maintenance ratio = A/B x 100% where: - A is the total number of place supplied with regulated voltage during 24 hours - B is the total number of place measured c.f.) 1. The status of inadequate voltage is when the average voltage during 30minutes deviates from the range of regulated voltage. 2. Utility standard low voltage is 220±13 [V]
SAIDI(Customer Average Interruption Duration Index)	SAIDI (Customer Average Interruption Duration Index) - This index indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption. Mathematically, this is given in Equation (3). SAIDI = Sum (Customer Interruption Durations) /Total Number of Customers served (3) To calculate the index, use Equation (4). SAIDI = Sum (riNi) / NT = CMI/NT (4) where : ri = Restoration Time for each Interruption Event ; CMI = Customer Minutes Interrupted ; Ni = Number of Interrupted Customers for each Sustained Interruption event during the; Reporting Period ; NT = Total Number of Customers Served for the Areas
SAIFI(System Average Interruption Frequency Index)	SAIFI (System Average Interruption Frequency Index) - The system average interruption frequency index indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Equation (1). SAIFI = Sum (Total Number of Customers Interrupted) / Total Number of Customers Served (1) To calculate the index, use Equation (2) below. SAIFI = Sum (Ni) / NT = CI / NT (2) where : CI = Customers Interrupted ; Ni = Number of Interrupted Customers for each Sustained Interruption event during the Reporting Period ; NT = Total Number of Customers Served for the Areas
DAFOR	Weighted DAFOR: Measures the percentage of the time that a unit or group of units are unable generate at its Maximum Continuous Rating (MCR) due to forced outages. The larger the unit (measured by its MCR), the greater its contribution towards the overall total.
Distribution SAIDI	Distribution SAIDI: Average interruption duration

	per customer.
Distribution SAIFI	Distribution SAIFI: Average number of interruptions per customer.
Transmission SAIDI	Transmission SAIDI: Average duration of forced outages per delivery point.
Transmission SAIFI	Transmission SAIFI: Average number of sustained forced outages per delivery point.
Transmission SARI	Transmission SARI: Average outage duration per interruption.
Under Frequency Load Shedding	Under Frequency Load Shedding: Customer load interruptions due to a generator trip.
Weighted Capability Factor: a) Year round availability of generating plant b) Winter availability of generating plant	Measures the percentage of the time that a units, or group of units, are available to supply some or all load. The larger the unit (measured by its Maximum Continuous Rating or MCR), the greater its contribution towards the overall total. Year-round availability of generating plants; Winter availability of generating plants
Average Duration (in minutes) of Unplanned Outages	
Number of Unsupplied Energy Interruptions	Unsupplied Energy is an indicator of customer reliability that combines the duration of interruptions to a customer's power supply with the energy not supplied as a result of the interruption. It is expressed mathematically as: Unsupplied Energy = (Sum (Ui x 60 min/hr)) / Pk - Where: Ui is the total unsupplied energy, expressed in MWh, at Delivery Point i over a one year period; Pk is the current year's system peak, expressed in MW; N is the total number of Delivery Points at the end of the reporting period. Unsupplied energy is normalized by the peak demand for energy to account for the changes in the volume of power delivered by the transmission system and allow a better assessment of changes in performance. The unit of measure for unsupplied energy is expressed in "system minutes". This represents the total energy that is not supplied to the customers normalized by the peak demand of the system (that occurred during the measurement period). The indicator includes both forced and planned sustained interruptions.
Reactive Plant Availability (%)	
Transformer Availability (%)	
Transmission Line Availability (%)	Transmission System Unavailability captures the impact of all outages on transmission lines, not just the outages that interrupt customers. Outages on transmission lines impact both end use customers and energy suppliers by limiting their ability to use the transmission system to its full extent. Transmission System Unavailability = ((Sum (Fi + Pi)) / (8760 x N)) x 100%. This

	indicator is expressed mathematically as: Where, Fi is the annual forced outage duration in hours for transmission line circuit i; Pi is the annual planned outage duration in hours for transmission line circuit i; N is the total number of declared in-service transmission line circuits; 8760 is the number of hours per year. The indicator tracks the extent to which the transmission system, including load and generation connection lines and interconnection lines, is not available for use by electricity market participants.
Absolute Percentage Error in Hourly Forecasting	
Composite Circuit Availability	Availability of bays = (Time Period – Total duration bay unavailable in Time Period) / (Time Period * Number of Bays). Bays considered for Composite Circuit Availability are Transformer Bays, Lines, Busbars, Series and Shunt Capacitors, SVC's, and Generator Bays. Circuit Availability in the case of Power Transformers and Lines means nothing prevents power from flowing between the two busbars the item is configured to be connected to.
Number of Daily Forecast Errors	
Number of Line Faults	This measure describes fault performance characteristics that have an impact on customers (i.e. seen as dips and momentary interruptions), as well as on transmission equipment (i.e. fault current). The measure is defined as the total number of line faults per 100 km of transmission line over a 12-month period. No differentiation is made between voltage categories.
Number of Major Events	A major event is an interruption incident that results in the loss of 1 system minute or more. The measure is scored on the basis of the degree of severity of these events. (See Appendix 1 Form SI 1c) The degree of severity of a major interruption is defined internationally as follows: Severity Degree 1: System minutes lost ≥ 1 and smaller than 10. Severity Degree 2: System minutes lost >10 and < 100. Severity Degree 3: System minutes lost ≥ 100. This measure tracks the number of significant interruption incidents. In the case of two (2) Degree 1 incidents, a further differentiation is made in the scoring on the basis of the total System Minutes lost.
Number of Supply Interruption Events	This measure is a count of the number of interruptions over the measurement period of a 12-month moving window. Where several customer supply points are affected by a single interruption incident, this is counted once for the purpose of this measure. All interruptions, including Major Events are reported in this measure.

Peak Hour Absolute Percentage Error	
Plant Health Index	This is a composite index comprising equipment failure numbers per plant item. Its intention is to give an overall impression as to how the Utilities plant is performing. Each plant item has a separate weighting in the index (dependant on perceived important of the plant item). The number of failures per equipment type (a 12 MMI value) is compared to a target, floor and ceiling value and then scored. The individual scores are added to determine the Plant Health Index Score
Power System Reliability	
Number of Significant System Events	The annual number of Significant System Events is an indicator of transmission safety related to the events that impact the transmission network performances. Only the incidents, for which the Utility is partly or entirely responsible for, are recorded: it concerns events related to the network, the system operating activities and the control system. Significant System Events are ranked according to a severity. The severity scale ranges from level 1 to 7.
Mechanical security rate of Sub-stations	The Utility implements a policy that aims at increasing the robustness of the overhead lines against large weather hazards like storms, snow and icing so as to prevent the occurrence of large incidents. The "mechanical security rate" of Sub-stations is a measure of the progress in the application of a policy that consists in connecting each delivery with a line mechanically reinforced. It is expressed in %. Three priority levels are defined for the delivery point according to the importance of the delivery point in term of electricity supply.
Quality of Supply	
Frequency of Cuts (short and long cuts)	The frequency of Cuts is an indicator of the supply reliability related to the cuts. A cut is specified by a lack of voltage for the customers connected to the transmission network. All lacks of voltage are counted even if the power demand is null when the incident happens. This indicator is expressed mathematically as: $\textit{Frequency of Cuts} = \frac{\sum C}{N}$ Where: $\sum C$ is the total number of cuts over a one-year period N is the total number of customer delivery points (distributors, industrial

	sites directly connected to the transmission network, except the specific large customers as Railway utilities) counted at the end of the year. A delivery point is defined by both a location and a corporate name for industrials or a transformer between the transmission network and the distribution network for distributors. The frequency of cuts is measured for: - Short cuts (a short cut is specified by a lack of voltage for customer lasting between one second and three minutes) - Long cuts (a long cut is specified by a lack of voltage for customer lasting more than three minutes). For thorough analysis needs, the Utility considers different long cuts grades: more than 6 hours, more than one hour (CTL), between 20 minutes and one hour (CL20+), between 3 minutes and 20 minutes (CL20-). This indicator is also measured, including or excluding major events.
Equivalent Interruption Time	The Equivalent Cut Time is an indicator of customer reliability related to the average duration of cuts for customers (distributors and industrial customers, except the specific large customers). This indicator is expressed mathematically as: *Equivalent Cut Time (minutes per year)* = 60 * $\frac{ENDn}{PMDA(n-1)}$ Where: - ENDn is the total unsupplied energy led by long cuts, excepting major events, for the year n - PMDA (n-1) is the average annual power, excepting losses, for the year (n-1). PMDA is calculated by dividing annual supplied energy (excepting losses) by 8760 (number of hours per year). For incidents attributable to a customer, only END induced for other customers are counted.
System Average Restoration Index (SARI)	This index is a measure of the average time taken to restore sustained supply point interruptions. SARI = Sum (Individual Sustained Supply Point Interruption Durations (minutes))/Number of Individual Sustained

	Supply Point Interruptions. The measure is calculated over a 12-month moving window.
System Minutes Lost	System Minutes Lost = Load Interrupted (MW) x Duration (minutes) *Utility Annual System Peak. Notes: *The Annual peak used for the current year is the previous year's peak demand. Utility System peak = Utility Generation + Imported Power (International) - Exported power (International). The figure used for the "Load Interrupted" is the actual load interrupted at the start of the incident and NOT peak demand. This figure is obtained from historical information (metered or approximated) and from customer feedback. Note that one System Minute is equivalent to an interruption of the total Utility system load for one minute at the time of the annual system peak.
System Minutes Lost < 1	This measure is the sum of system minutes lost per incident over a 12 month moving window. Only system minute events less than 1 system minute are counted in this index. This measure describes the underlying performance (severity of the load interrupted) over a 12-month period. Major events are excluded from this measure, and are reported separately.
Total Harmonic Distortion - THD	This measure is a summation of the sinusoidal components of the fundamental waveform (i.e. 50Hz.) that have frequencies that are an integral multiple of the fundamental frequency. This measure records the percentage of permanent sites exceeding the Voltage Total Harmonic Distortion limits These limits are defined for each site in the Transmission/Distribution Supply Agreement. The negotiated limits are based on NRS 048-2:2003.This measurement and assessment of Total Harmonic Distortion is defined in accordance with NRS 048-2, Section 4.1.An exception is that seven violations of the limit over the twelve-month window at a given site may be excluded from the data (i.e. a maximum of seven of the 365 values for the year). This provision is included for 2004 until more experience has been gained with the new NRS 048-2 weekly measurement (previously this was a daily measurement).
Unplanned Circuit Unavailability	Planned Unavailability is when plant is switched out to do normal maintenance. Unplanned Unavailability is when plant trips or when it is switched out to repair a fault that would otherwise have eventually lead to a trip· If plant is switched out for voltage control, is it still available? Y· If plant is switched out during network reconfiguration or during the restoration after an incident, is it still available? Y· If plant is switched

	out in order to be able to work on another, is it still available? N· If a line is switched out to prevent it from tripping during a cane or field fire, is it still available? N· If a transformer is switched out to prevent it from overloading, is it still available? N· If plant is switched out only to afford a customer the opportunity to do maintenance work on their side, is it still available? Y· If a line is switched off ARC to do live line maintenance, is it still available? Y· If one or both ends of a line is put on transfer or bypass in order to do breaker maintenance, is it still available? Y· If there is a bus zone operation or a bus strip operation that takes out a transformer or line but the fault was not on that bay, is the transformer or line available or not? Y· If plant was switched out but it was the wrong plant to switch out (operator error), is the plant available or not? N· If plant trips out, but no reason for the trip could be found and it is successfully put back into service, was it unavailable for that period? Y· System Ops define an outage as unplanned if the booking has not been made 14 days in advance. Is this the definition we will use to make the distinction between planned and unplanned?
Voltage Magnitude (Voltage Regulation)	This is a measure of the ability of the system to control the steady state r.m.s. voltage within set limits above and below the declared voltage. Exceeding either limit is considered a deviation. This measure records the percentage of permanent sites exceeding the stipulated SA limits. Voltage Regulation is defined in accordance with NRS 048-2:2004, (Section 4.1). The Voltage Regulation limits are defined at each site in by the Transmission/Distribution Supply Agreement. An exception to this is that for Voltage Regulation, 3 consecutive 10 minute violations are allowed (i.e. the 4th exceed is reported). Regardless of this exception, any site where the voltage exceeds the Design Value or the nameplate data (whichever is the more stringent) will be included in the report. The Design Values are ± 5 % for >= 400 kV and ± 10 % for <= 275kV.
Voltage Unbalance	Voltage Unbalance arises in a poly-phase system when the magnitudes of the phase voltages or the relative phase displacements of the phases (or both) are not equal. The Voltage Unbalance is calculated as the negative phase sequence over the positive phase sequence, expressed as a percentage. This measure records the percentage of permanent sites exceeding the Voltage Unbalance limits. These limits are defined for each site in the Transmission/ Distribution Supply Agreement. The negotiated

	limits are based on NRS 048-2:2004.
Equivalent Availability Factor	Identical to NERC
Equivalent Breakdown Maintenance Factor	Identical to NERC
Equivalent Forced Outage Factor	Identical to NERC
Equivalent Planned Outage Factor	Identical to NERC
Average Annual Availability	The annual average % availability of the England & Wales electricity transmission system: 100 X (1 – (Total hours of circuit unavailability / (Hours per year X Total number of circuits)))
Average Annual Planned Unavailability	The annual average % unavailability of the England & Wales electricity transmission system due to planned outages, i.e. those outages planned with greater than 7 days notice: 100 X (Total hours of circuit planned unavailability / (Hours per year X Total number of circuits))
Average Annual Unplanned Unavailability	The annual average % unavailability of the Utility electricity transmission system due to unplanned outages (outages occurring with less than 7 days notice) for repair work, this includes fault outages and outages forced by plant breakdown: 100 X (Total hours of circuit unplanned unavailability / (Hours per year X Total number of circuits))
Short Term Planning Churn	This measure records the proportion of changes to the outage plan that are greater than 14 days notice and categorizes changes with less than 14 days notice as compliant or non-compliant based on the following criteria: Serious defects, Knock on's, Faults, Failure of outages to return to service due to commissioning delays or significant defects found during maintenance. The measure is expressed as a percentage of total changes that are compliant within each week on a rolling 12 week basis reported monthly.
Unsupplied Energy (excluding "3 customers or less")	The energy unsupplied due to unplanned outages on the Utility electricity transmission system. Energy Unsupplied is calculated from: MW at time of loss x Duration of loss (Mins)/60 = MWh This measurement represents unsupplied energy to groups of more than 3 customers.
Unsupplied Energy (including "3 customers or less")	The energy unsupplied due to unplanned outages on the Utility electricity transmission system. Energy Unsupplied is calculated from: MW at time of loss x Duration of loss (Mins)/60 = MWh This measurement represents unsupplied energy to all groups of customers including incidents in the "3 customers or less category".
Duration of Delivery Point Interruptions: a) SAT voltages (115kV and above)	Duration of Delivery Point Interruptions is an indicator of customer reliability related to the duration of interruptions, that is, the time for which supply of energy is interrupted for customers supplied from the transmission system. This indicator measures the duration of interruptions to customer delivery points. It is

	expressed mathematically as: Duration of Delivery Point Interruptions = Sum (Di)/N where: Di is the total effective interruption duration of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over one year period N is the total number of Delivery Points at year-end of the reporting period Subset of Duration of Delivery Point Interruptions Duration of forced sustained delivery point interruptions on 115kv system and above which includes all multi-circuit supplied delivery points.
Frequency of Delivery Point Interruptions: a) SAT voltages (115kV and above)	Frequency of Delivery Point Interruptions is an indicator of customer reliability related to interruptions, that is, outages on the transmission system that interrupt the supply of energy to transmission customers. This indicator measures the number of interruptions to the supply of power to customer delivery points. It is expressed mathematically as: Frequency of Delivery Point Interruptions = Sum (Mi + Si)/N where: Mi is the total number of Momentary Interruptions experienced at Delivery Point i over one year period Si is the total number of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a year period N is the total number of Delivery Points at the end of the reporting period This indicator includes all forced and planned interruptions, both momentary and sustained. Subset of Frequency of Delivery Point Interruptions Frequency of forced, including momentary and sustained delivery point interruptions on 115kv system and above which includes all multi-circuit supplied delivery points.
Unsupplied Energy	Unsupplied Energy is an indicator of customer reliability that combines the duration of interruptions to a customer's power supply with the energy not supplied as a result of the interruption. It is expressed mathematically as: Unsupplied Energy = Sum (Ui x 60 min/hr)/Pk Where: Ui is the total unsupplied energy, expressed in MWh, at Delivery Point i over a one year period Pk is the current year's system peak, expressed in MW. N is the total number of Delivery Points at the end of the reporting period. Unsupplied energy is normalized by the peak demand for energy to account for the changes in the volume of power delivered by the transmission system and allow a better assessment changes in performance. The unit of measure for unsupplied energy is expressed in "system minutes". This represents the total energy that is not supplied to the customers normalized by the peak demand of the system

	(that occurred during the measurement period). This indicator includes both forced and planned sustained interruptions.
Duration of Delivery point interruptions (25kV and up)	Duration of Delivery Point Interruptions is an indicator of customer reliability related to the duration of interruptions, that is, the time for which supply of energy is interrupted for customers supplied from the transmission system. This indicator measures the duration of interruptions to customer delivery points. It is expressed mathematically as: Duration of Delivery Point Interruptions = Sum (Di)/N; where: Di is the total effective interruption duration of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over one year period; N is the total number of Delivery Points at year-end of the reporting period.
Unsupplied Energy	The Reliability goal is a key aspect of senior management's obligations to long term management of one of our key customer deliverables, transmission reliability. 3 year rolling average of MWh interrupted per delivery point outage was used. * The annual calculation is based on the total MWh interrupted in the year divided by the total number of delivery points interrupted in the year to determine the average MWh/dp outage. * Major storms will be excluded: a major storm is equal to any uncontrollable event that results in 50% or greater contribution to the target amount in any one year.
Number of Interferences (50-400kV)	Number of Interferences is the total number of Momentary and Sustained Interferences with no effect on energy supply.
Unsupplied Energy	Number, duration and unsupplied energy of Delivery Point Interruptions (50-400kV). Number of Delivery Point Interruptions is the total number of Momentary and Sustained Interruptions experienced at Delivery Point i over a one year period. Duration of Delivery Point Interruption: time per Interruption. Unsupplied Energy per interruption and Total.

Table D4
CUSTOMER

Corporate Level Measures	Definition
Customer Service Satisfaction Survey	BCTC conducts an annual Customer Satisfaction Survey in the fiscal fourth quarter to assess how we're doing as a company. Commercial, Government and Public stakeholders are interviewed as well as BC Hydro Senior Managers. The survey measures awareness,

	knowledge, and impressions from the stakeholders in a number of ways. BC Hydro managers are questioned about the Utilities Sever Year Priorities, Safety and Reliability, and Relationships. Concerns about the transfer of responsibilities from BC Hydro to BCTC are also identified.
Customer Satisfaction Survey of Generator Customers	Utility surveys customers on how satisfied they are with the service that they have been receiving. Surveys are administered to transmission connected customers and generators, and survey questions are focused on areas which are important to customers such as reliability, communications, relationships, and responsiveness.
Customer Satisfaction Survey of Transmission Customers	Utility surveys customers on how satisfied they are with the service that they have been receiving. Surveys are administered to transmission connected customers and generators, and survey questions are focused on areas which are important to customers such as reliability, communications, relationships, and responsiveness.
Customer Satisfaction Survey hosted by Government	The Government surveys customers supplied with electricity on how satisfied they are with the service that they have been receiving. Surveys are carried out once a year by special opinion survey groups. Survey questions are focused on areas which are important to customers such as human service, electricity quality, electricity charge and corporate image.
Customer Satisfaction Survey hosted by our company for 66kV and above	Our company surveys the customers of 66kV and above on how satisfied they are with service that they have been receiving. Surveys are carried out once a year by special opinion survey groups. Survey questions are focused on areas which are important to customers such as new reception work, electricity quality, unexpected outage guidance work and inconvenient matter reception work.
CEA Customer Service Index	Calculation: This index is calculated from the Public Attitudes Research survey conducted annually by an independent consultant hired by the Electricity Association within the Country. The objective of the survey is to track and measure any changes in public attitudes toward their electric utility. The Customer Service Index is a weighted composite of customer ranking of (1) the perceived level of importance, and (2) their satisfaction level with the 15 different issues related to overall customer satisfaction:· Number of power outages · Listens/acts upon customer concerns· Ensures sufficient future supply · Speed in restoring power· Quality of customer

	service · Accuracy of billing· Price · Bills easy to read and understand· Environmental responsibility · Cares about its customers· Concern for public safety · Power quality free from voltage fluctuations · Community contributions · Maintains electricity system· Encourages efficient use of electricity. Measure Rationale: The Country based utility Association customer service index provides a benchmark for comparing the Utilities perceived performance on customer service with that of other Canadian electrical utilities. Data Collection: The Country based Industry Utility Association - Public Attitudes Research survey is conducted annually in the spring. The national survey size is a weighted sample of 2400. The Utility share of the national sample size is about 200. Thus the results are statistically valid for comparisons at a national level, but low if used specifically for evaluating Utility customer satisfaction. The Country Based Utility Association - Public Attitudes Committee releases results in June.
Natural gas market share	
Public contact - natural gas and electric	
Retail distribution rates: natural gas	
Retail rates: electricity	
System average interruption duration	
System average interruption frequency	Calculation: Outage time: = Total customer-minutes of interruption per year/Total customers served. The average cumulative interruption duration per year per customer served; or System Average Interruption Duration Index (SAIDI), is a commonly used measure of service reliability which measures the length of interruptions including the service restoration time. Outage frequency: = Total customer-interruptions/Total customers served. This index measures the average number of interruptions per year per customer served. Utility measures the System Average Interruption Frequency Index (SAIFI); which is a commonly used measure of service reliability, and measures the frequency of interruptions. For calculation of either SAIDI or SAIFI, an interruption is the loss of service to one or more customers. Interruption duration is the period from start of an interruption to a customer until service has been restored to that customer. Currently, the Utility records only interruptions of duration greater than one minute. (Source: 2000 Annual Service Continuity Report on Distribution System Performance). Measure Rationale: Part of the Corporate mission is to provide for the continuance of a supply of energy adequate for the needs of the province. SAIDI

	and SAIFI measure the continuity of electricity supply. The Utility Customer Satisfaction Tracking Study has determined that customer satisfaction levels decrease as the perceived frequency and perceived duration of outages increases. With competition and deregulation facing the electric utility industry, service quality is one of the major factors that will influence customers' choice of energy supplier. When energy is treated as a commodity, high quality of service becomes the primary marketing tool in the utility's drive for obtaining and maintaining customers. The term "Service Quality" generally consists of two parts, the 'continuity of supply' and the 'regularity of supply'. The continuity of supply is known as "Service Reliability" and the conformance of the power supply to pre-defined regularity standards is called "Power Quality". (Source: Adapted from the Service Quality home page on MPower.) For a description of power quality, see the discussion of Total Harmonic Voltage Distortion at that same location on MPOWER. Service Quality --> continuity of supply --> service reliability --> SAIDI and SAIFI Service Quality --> regularity of supply --> power quality --> VTHD Data Collection: Outages of duration longer than one minute are recorded on the Service Interruption Reporting portion of the Transformer Load Management System.
Customer Satisfaction Index: a) Residential b) Commercial	Customer ratings of importance and satisfaction on 16 applicable service attributes.
Community Rating	
Customer Survey	
Annual Customer Meetings / Presentations	Annual meetings with each specific Transmission Customer. Topics of discussion are as follows: • Reliability • Communications • Relationships • Responsiveness • Outage Scheduling

Table D5
EMPLOYEE

Corporate Level Measures	Definition
Accident Severity Rate (ASR)	ASR is equal to the (total number of days lost or days charged for all disabling injuries) x 200,000 divided by the total (number of hours worked by employees). The unit of measure is number of days lost per 200,000 hours worked. The measure applies to direct employees of the business only; it does not include those workers contracted by the business.
Loss Time Injury Frequency Rate	Number of Incidents of Fatalities, Permanent Total Disabilities, Permanent Partial Disabilities, Temporary Total Disabilities and Medical Attention

	Cases per 200,000 Hours Worked. This includes both injuries and work related illness. The total number of hours worked includes number of hours of paid overtime worked. This measure applies to direct employees of the business only; it does not cover those workers contracted by the business or those working at home.
Serious Incidents	The numbers of potentially serious incidents where there is the reasonable potential that they could result in a serious injury or death. Serious incidents would be defined to be high Maximum Reasonable Potential for Harm (MRPH) incidents related to 6 categories: electrical incidents, preventable motor vehicle accidents, falls from a different level, objects dropped, work equipment related, and asset equipment failure related. The categories included in the Serious Incident measure are those that historically display a high potential for causing severe injury. The measure is calculated as "the number of serious incidents under the above specified six categories" and applies to direct employees of the business only; it does not cover those workers contracted by the business.
Serious Lost Time Injuries	The number of serious lost time injuries resulting from serious incidents. This measure will help to distinguish between those incidents that had the potential to cause injury versus those that actually resulted in an injury to staff. The measure is calculated as "the number of injuries due to serious incidents under the specified six categories" and applies to direct employees of the business only; it does not cover those workers contracted by the business.
Loss Time Injury Frequency Rate	Number Incidents of Fatalities, Permanent Total Disabilities, Permanent Partial Disabilities, Temporary Total Disabilities and Medical Attention Cases per 200,000 Hours Worked. This includes both injuries and work related illness. The total number of hours worked includes number of hours of paid overtime worked. This measure applies to direct employees of the business only; it does not cover those workers contracted by the business or those working at home.
company medical care survey	medical survey: feedback to manager from points raised by medical officer
employee satisfaction survey	satisfaction: two-yearly score held by an external consultant; trend analyses
illness leave (short term)	illness leave: % of employee time
number of accidents and incidents	accident: unwanted occurrence on Utility premises, caused by unsafe action or unsafe situation with the consequence of harm to persons or damage to the installations. incident: unwanted occurrence on Utility premises, caused by unsafe action or unsafe situation with the potential consequence of harm to persons or damage to the installations
Frequency Rate of Injury	Frequency Rate of Injury indicates the frequency of the injury incidents which has occurred in 106 hours. It is expressed as Frequency Rate of Injury = injury

	incidents x 106 / annual labour time
Frequency Severity Index	Frequency Severity Index is the index indicating the frequency and severity rate. It is expressed as Frequency severity rate = square root (Frequency rate of injury x Severity rate of injury)
Severity Rate of Injury	Severity Rate of Injury indicates the days lost in 103 hours. It is expressed as Severity Rate of Injury = total lost days x 103 / annual labour time
Percentage of designated group members in Utility Workforce	Calculation: Number of Employees belonging to the designated group X 100% Total of Utility Employees. Definitions of designated groups: Aboriginal Peoples: Persons who are Indians, Inuit or Metis. Members of Visible Minorities: Persons, other than Aboriginal peoples, who are non- Caucasian in race or non-white in colour. Persons with Disabilities: Persons who have a long-term or recurring physical, mental, sensory, psychiatric or learning impairment and who (a) consider themselves to be disadvantaged in employment by reason of that impairment, or (b) believe that an employer or potential employer is likely to consider them to be disadvantaged in employment by reason of that impairment and includes persons whose functional limitations owing to their impairment have been accommodated in their current job or workplace. (Source: The Federal Employment Equity Act) Provincial demographics are available from census data. Measure Rationale: This measures progress toward corporate employment equity goals, as well as facilitating external reporting of workforce demographics. It is the Utilities target that the percentage of employees from the designated groups matches their representation in the population of Manitoba. For most, if not all, of the designated groups, this is greater than their labour force participation rate. It is recognized these groups are historically disadvantaged in employment opportunities and special initiatives are required to 'ameliorate conditions of past disadvantage' 1. 1The Constitution Act - Canadian Charter of Rights and Freedoms, Sec. 15 (2) Data Collection: Data on equity group membership is collected by surveying the Utility workforce, and is kept up to date by supplying a Self-Declaration Survey to all new hires. Participation in the survey is voluntary; an individual may decline to participate for any reason by signing the appropriate section and returning the form. The return of the survey form is mandatory, in either event. Declaration data is updated monthly from the PayPers HRIS system to produce reports and statistical analysis of the current workforce. Aggregate statistical reports are provided to various areas of the Corporation for planning and reporting use.

Percentage of non-entry positions filled by external applicants	Calculation: % NEL Positions Filled Externally = NEL Positions Filled Externally/Total NEL Positions Filled Where:· NEL Positions are any classification pay-grade 14 or above.· Exceptions are: all Trainee positions (i.e., Technical, Trade, EIT, Commerce, and IT), Laboratory Technician I, Lawyer Junior, Articling Law Student, Process Support Analyst I, System Developer I, Support Specialist I, HR System Developer Note: Temporary employment (e.g., term, seasonal, local hire, temporary, student, casual) is not included Measure Rationale: This measure is intended to indicate how effectively the corporation balances the input of new talent from outside with the advancement of talent within. It is based on the number of non-entry level positions filled during each quarterly period. It is a lagging measure of overall performance in developing the internal job pool. The target range of 8%-12% is based on the historical average and strongly favours the Utilities traditional "promote from within" practices. (External benchmarks indicate that Top 10% firms fill 61.46% of jobs from within, compared to 34.90% of Bottom 10% firms.) Data Collection: Data on all requisitions (staffing requests) is maintained by HR Advisors in HRMS. Following the end of each quarterly period, data is extracted from HRMS and a report is generated; summary information is provided divided by Business Units. Results are verified by ESS-Employment.
Disabling and Medical Aid Injuries	Cumulative number of disabling and medical aid injuries to date versus target. This represents the rate of all disabling and medical aid injuries per hours "worked" per 100 employees.
Disabling Injuries	Cumulative number of disabling injuries to date versus target. This represents the rate of all disabling and medical aid injuries per hours "worked" per 100 employees
Near Miss Reports	Cumulative number of near miss incidents reported versus target.
Disability	To measure the organizations' employment equity targets as per set rules.
Disabling Injury Incidence Rate (DIIR)	The DIIR is a proportional representation of the occurrence of industrial disabling injuries. The DIIR rate reflects a rough estimate of the percentage of the workforce that suffered a disabling injury in the preceding twelve months. DIIR = (Number of disabling injuries * 200,000)/(Total number of employee man-hours of exposure)
Fatalities	Measures the number of fatalities.
Gender Equity	To measure the organizations' employment equity targets as per set rules.
Human Resources Sustainability Index	To measure the health of Human Resource management in the organization.
Leadership Inspections	The objective is to demonstrate visible felt leadership

	by Corporate Executives (Top 200) in all divisions. It is measured by the percentage of inspections complete.
Lost Time Incident Rate (LTIR)	To monitor the number of lost time incidents as expressed per number for working-hours. Note: Lost time incident rate is calculated for a 12 month period. The figure 200,000 refers to the average number of man-hours worked by 100 employees in one year. LTIR = (Number of Lost Time Incidents * 200,000)/(Number of Working Hours)
Racial Equity	To measure the organizations' employment equity targets as per set rules.
Severity Rate	Used to monitor the severity of lost time incidents, including fatalities, occupational diseases and other incidents that resulted in lost time. The numbers of incidents are categorized into the following groups: Number of Occupational Diseases, Number of Lost time incidents where the number of days lost is equal to or exceed 14 days. (This will include fatalities. Note: the number of days lost per fatality equals 6,000). Number of Lost time incidents where the number of days lost is equal to or between 4 and 13 days. Number of Lost time incidents where the number of days lost is equal to or between 1 and 3 days.
Staff Retention Strategy/Initiatives	To develop a Staff Retention Strategy to increase the staff retention ability of Transmission in an environment where the global demand for scarce and critical skills are growing.
Total Recordable Incident Rate (TRIR)	Consists of all incidents where people are injured, excluding first aid treatment cases. Used to monitor the Total Recordable Incidents as expressed per number of working hours. Note: Recordable incident rate is calculated for a 12 month period. TRIR = (Number of total recordable incidents * 200,000)/(Number of working hours)
Transmission People Development Strategies/Initiatives	To develop a Transmission People Development Strategy and initiative by taking into account the global drive to increase electricity supply capacity and the growing demand for scarce and critical skills.
Transmission Succession Management	To develop a Transmission Succession Management Strategy to increase knowledge continuity in an environment where the global demand for scarce and critical skills are growing as well as taking the age profile of the current skills into account.
Employee Numbers	Total number of employees
Employee Survey Index	
Lost Time Injuries	No. of injuries causing employee to off work
Safety Index	
Sick Leave	Annualized avg sick day per employee
Training	Annualized training day per employee
Accident Severity Rate (ASR)	ASR is equal to the (total number of days lost or days charged for all disabling injuries) x 200,000 divided by the total (number of hours worked by

	employees). The unit of measure is number of days lost per 200,000 hours worked. The measure applies to direct employees of the business only; it does not include those workers contracted by the business.
Loss Time Injury Frequency Rate	Number of Incidents of Fatalities, Permanent Total Disabilities, Permanent Partial Disabilities, Temporary Total Disabilities and Medical Attention Cases per 200,000 Hours Worked. This includes both injuries and work related illness. The total number of hours worked includes number of hours of paid overtime worked. This measure applies to direct employees of the business only; it does not cover those workers contracted by the business or those working at home.
Serious Incidents	The numbers of potentially serious incidents where there is the reasonable potential that they could result in a serious injury or death. Serious incidents would be defined to be high Maximum Reasonable Potential for Harm (MRPH) incidents related to 6 categories: electrical incidents, preventable motor vehicle accidents, falls from a different level, objects dropped, work equipment related, and asset equipment failure related. The categories included in the Serious Incident measure are those that historically display a high potential for causing severe injury. The measure is calculated as "the number of serious incidents under the above specified six categories" and applies to direct employees of the business only; it does not cover those workers contracted by the business.
Serious Lost Time Injuries	The number of serious lost time injuries resulting from serious incidents. This measure will help to distinguish between those incidents that had the potential to cause injury versus those that actually resulted in an injury to staff. The measure is calculated as "the number of injuries due to serious incidents under the specified six categories" and applies to direct employees of the business only; it does not cover those workers contracted by the business.
All Injury Frequency Rate	AIFR = (medical aid injures + Lost time Injuries) / 200,000 hours worked. This includes injuries to AltaLink staff and contractors working in excess of 500 hours per year.
Employee Development	Number of days of further training per employee. This measure applies to all employees.

Appendix E

CEA's Policies on the Use of Benchmarking Data in Regulatory Settings: What Stakeholders Need To Know

June 5, 2006

The Canadian Electricity Association (CEA) recognizes that benchmarking information has been used by its members for the purposes of performance improvement, and increasingly in regulatory settings to assess relative performance of electric utility companies.

Given that there are significant differences in terms of scope, as well as the need for granularity and accuracy for these two distinctly different uses for benchmarking data, CEA has developed policies governing the use of benchmarking data in regulatory settings.

Best Practices and Performance Improvement

For many years, Canadian utilities have been participating, via CEA and other benchmarking organizations, in studies concerning the continuity of service, customer satisfaction, employee safety and cost related indicators. The primary purpose of CEA's benchmarking efforts over the past two decades has been to assist member in improving their operational performance. Since the main focus of these efforts was to improve operational performance, through the identification of utility "best practices", the data collection methods were not of sufficient quality for use in benchmarking for Regulatory purposes.

Participation in benchmarking studies is typically voluntary. Regulatory actions using data for purposes it was not intended is likely to result in incorrect results and could therefore inhibit participation in benchmarking activities for the purpose of operational improvement. This would adversely impact the ability to identify best practices and the pursuit of performance improvement and ultimately will do a disservice to the ratepayer.

Given the inherent challenges in benchmarking with others, utilities have tended to limit the use of "peer group" benchmarking to discovery and identification of "best practices". For utilities, the relative ranking of the participants or the comparison of a utility to a composite has limited value and, when taken at face value, has little correlation to individual utilities' performance. The ultimate goal is performance improvement through informed decision making and the determination and utilization of "best practices".

The Challenges of Peer Group Benchmarking

By its very nature, "peer group" benchmarking is an extremely challenging undertaking. Attempts to account for unique operating and business environments are complex and require detailed information. This detailed information, while more than adequate for the "discovery" process which is at the heart of performance benchmarking, is often not of sufficient quality to be used in regulatory environments.

The Policies

CEA is committed to working cooperatively with regulatory authorities to develop the right processes and identify the best indicators, so that the benchmarking data used in the regulatory realm is of value. The CEA policies governing this are as follows:

Developing the Framework

Appropriate benchmarking performance information (which is accurate, verifiable, and verified and includes the proper consideration, caveats, standardized interpretations and collection methodologies) will be developed by CEA for use in Regulatory settings. Participating CEA members commit to work towards providing data that meets these criteria, on a yearly basis, that will be used in the development of an agreed-to set of indices.

Peer-to-Peer Not Recommended

CEA members do not support a peer-to-peer approach when assessing a company's performance and especially to establish pass/fail criteria for breach and consequence, due to the complexity of identifying true "peers". This complexity is due to differences between companies' geography, climate, customer mix, growth rate, system age, resource mix, degree of interconnection, impact of significant events, and a range of other factors.

Trending Performance

Trending an individual utility's own performance over time should be used as opposed to single year comparisons.

A Cooperative Approach

CEA and its members will work cooperatively with regulatory authorities to ensure that indicators used in regulatory settings are accurate, verifiable and verified, and are meaningful. Through CEA's Councils, and in cooperation with members of the Canadian Association of Members of Public Utility Tribunals (CAMPUT), appropriate benchmarking indicators for assessing individual company performance over time will be developed.

Ensuring Quality Indicators

Participating CEA members will meet or exceed standards of data quality, integrity and consistency of reporting for these indicators.

Commitment to Performance Improvement

Improved productivity and performance result in significant benefits to companies, shareholders and rate-payers. CEA therefore will continue to promote the use of benchmarking to identify best practices for performance improvement.

The Right Composite Benchmarks

Only composite benchmarks deemed appropriate for regulatory environments, will be produced. Participants are cautioned that publication of metrics not identified as appropriate for regulatory environments in composite or other form in a regulatory forum or elsewhere may result in blocking further participation by that member or the termination of further CEA benchmarking on that metric.

The Way Ahead

CEA's Transmission Council

The Transmission Council has instituted a one-year transition for the implementation of the Benchmarking Data in Regulatory Settings (BDRS) policy. Composite transmission indicators for 2004 and 2005 will be available during 2006 similar to those made available in past years. With respect specifically to the Committee on Corporate Performance and Productivity Evaluation (COPE), there will be no executive summary in accordance with a decision made by COPE members in 2005. Participants will however be able to use indicators in the same way they have in previous years. This allows members to prepare filings and provides a window of opportunity to prepare regulators for changes as to what will be available in 2007.

The Transmission Council, through its Benchmarking Task Group (TC-BMK-TG), is in the process of creating the criteria for the identification of appropriate indices consistent with the BDRS policy.

The TC-BMK-TG will apply these criteria in the development of regulatory-appropriate Key Performance Indicators (KPIs) in both the short and long-term. Short-term, the TC-BMK-TG will identify KPIs that can be made regulatory-ready within the year. Long-term, the TC-BMK-TG will consider the best KPIs for regulatory purposes and determine whether their development is feasible.

Through the TC-BMK-TG, the Transmission Council is ensuring on-going engagement with CEA's data gathering and benchmarking programs, including COPE, the Consultative Committee on Outage Statistics (CCOS), and Occupational Health and Safety program

The first Transmission KPIs are expected to be submitted to the Transmission Council for approval in Fall, 2006.

Following the 2006 transition year, CEA will only produce national composite Transmission benchmarks for those indicators which are approved by the Transmission Council, as appropriate for use in regulatory settings. Of course, this does not limit in any way the company-specific information which regulatory authorities may seek.

Appendix F

Example of Electricity Utility Regulatory Submission for Establishing a Historic Baseline of Transmission Reliability Performance

1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point ("CDPP")[3] level, consistent with system wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken;
- establish any circumstances in which the performance standards will not apply.

On May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the OEB for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the Board.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid

[3] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

2.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components (1) Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and (2) Individual CDPP Standards that maintain a customer's individual historical delivery point performance. Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized below.

2.1 Performance Standards Based on Size of Load Being Served: Group CDPP Standards

In this component, the CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[4] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1 below.

[4] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

Table 1

Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (min/yr)	89	360	22	140	11	55	5	25

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[5] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. Included in this category of excluded events are the 1998 ice storm and the 2003 blackout.

[5] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption, but are charged against Hydro One's reliability performance for other interrupted customers.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum CDPP standards of performance, for each of the four load groups or bands, are to be used as triggers by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the minimum CDPP Standard for the delivery point of the load size group or band (referred to as a performance outlier or outlier) or when a delivery point customer indicates that analysis is required. When an outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability.

2.2 Performance Standards to Maintain Historical Delivery Point Performance: Individual CDPP Standards

In this component, the CDPP Standards are intended to maintain the historical reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1 above). In order to identify customer delivery points with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each delivery point based on that delivery point's historical 1991-2000 average performance, plus one standard deviation (the "historical baseline"). The historical baselines exclude outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical trend of the measure (such as the 1998 ice storm and the 2003 blackout). Also, for delivery points that came into service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.2.1 <u>Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards</u>

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's performance.

2.3 REMEDIAL COSTS TO ADDRESS GROUP AND INDIVIDUAL PERFORMANCE OUTLIERS

For Group and Individual Performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets to what was designed originally. These costs include appropriate asset sustainment costs, on-going maintenance costs and costs associated with asset refurbishment or replacement. Historically, Hydro One has spent approximately $700 million per year on OM&A and Capital expenditures on the transmission system. About half of these expenditures are related to sustainment work to ensure that transmission assets are in "good" working order and able to perform as intended. These expenditures are made on an ongoing basis consistent with "good utility practices," irrespective of actual delivery point performance or of whether a delivery point is a performance outlier. No customer contribution formula is required for these normal sustainment expenditures.

For Individual Performance outliers, Hydro One will restore the delivery point to the historical level of performance. Hydro One's remedial work will not include capital reliability improvements that significantly enhance the reliability of supply relative to the reliability that was inherent in the original system design or configuration of supply.

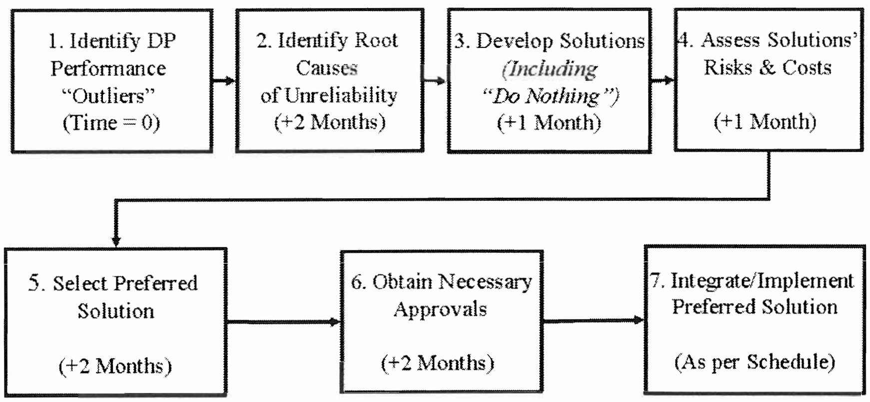
For Group Performance outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue[6] associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by affected delivery point customers. In cases where specific transmission facilities are serving two or more customers in common with outlier performance, Hydro One will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for these investments is to be consistent with the TSC, specifically: (i) Hydro One will not attribute the costs associated with network investment to any customer and any variance from this approach requires a determination by the Board; (ii)
the costs of preparing the final estimate for reliability improvements required to address performance outliers is the only portion of the technical and financial evaluation that is to be included as part of the cost of the remedial work; and (iii) where a customer contribution is required to improve or expand the transmission system to correct outlier performance, the customer will be given contracting privileges consistent with those applicable to contestability for new customer connections. In addition, affected delivery point customers are responsible for all of the costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost sharing arrangements are to be detailed in a connection and cost recovery agreement with the affected customers.

[6] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

2.4 Process Timelines to Address Performance Outliers

The process and associated timelines that will be followed to address performance outliers – both for Group and Individual outliers - and determine the preferred course of action are provided below.



1. Time = 0: Hydro One identifies, annually, delivery point performance "outliers" for both Group and Individual standards. Hydro One will notify customers that are supplied from these performance outlier delivery points and solicit their feedback/issues/concerns on their reliability of supply.

2. Within 2 months: Hydro One will determine the root causes of unreliability associated with each performance outlier identified in (1).

3. Within 1 month: Hydro One will develop solutions to address performance outliers, including, (i) the work to restore and sustain the inherent reliability performance of the existing assets to what was designed originally; and (ii) for Group Performance outliers, the additional capital improvements required to improve the performance of an outlier to within standard and beyond what was designed originally. Hydro One will discuss the proposed solutions with affected customers.

4. Within 1 month: Hydro One will determine the costs and assess the risks of the solutions, including any customer capital contributions required for option (ii) above. Hydro One will present these costs to customers for their review and assessment.

5. Within 2 months: Hydro One and customers select the preferred option and where appropriate customers state their intention on whether to proceed with capital improvements that involve customer contributions identified in option (ii) above.

6. Within 2 months: Hydro One and customers obtain the necessary approvals to proceed with the preferred solutions to address performance outliers.

7. Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

When Hydro One completes work to restore delivery point performance to standard, it continues to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then Hydro One will review the work that has taken place and will identify corrective action. Hydro One will not as a practice wait another 3 years and start a new technical and financial evaluation. Hydro One reviews and identifies customer delivery point performance annually, regardless of the investment history.

Appendix G

Glossary of Terms and Definitions

-- A --

AAA	-----------------	Average Annual Availability
AASDE	-----------------	Annualized Average Sick Day per Employee - Sick Leave
ACCC	-----------------	Australian Competition and Consumer Commission
ACMP	-----------------	Annual Customer Meetings and Presentations
AICPA	-----------------	American Institute of Certified Public Accountants
AID	-----------------	System Average Interruption Duration
AIF	-----------------	System Average Interruption Frequency
AIFR	-----------------	All Injury Frequency Rate
AIT	-----------------	Average Interruption Time
APIE	-----------------	Average Percentage of Ill Employees
ASR	-----------------	Accident Severity Rate
ATDE	-----------------	Annualized Training Days per Employee - Training
Av of B	-----------------	Availability of Bays

-- B --

BEE	-----------------	Black Economic Empowerment
BES	-----------------	Bulk Electricity System

-- C --

CAIDA	-----------------	The total amount of CML/the total number of customers and the time period (minutes)
CAPEX	-----------------	Capital Expenditure
CCOS	-----------------	Consultative Committee on Outage Statistics
CEA	-----------------	Canadian Electricity Association
CEER	-----------------	Council of European Energy Regulators
CICA	-----------------	Canadian Institute of Chartered Accountants
CLI	-----------------	Customer Load Interruption Performance
CML	-----------------	(The number of customers) x total restoration time (in minutes)
CMCS	-----------------	Company Medical Care Survey
Com	-----------------	Commercial
CPI	-----------------	Connection Point Interruption Performance
CPM	-----------------	Corporate Performance Metrics CPM
CSI	-----------------	Customer Satisfaction Index
CSS	-----------------	Customer Satisfaction Survey

-- D --

DIIR	----------------	Disabling Injury Incidence Rate
DGM %	----------------	Percentage of designated group members in utility Workforce
DMAI	----------------	Disabling and Medical Aid Injuries
Ds	----------------	Distribution

-- E --

EBITDA	----------------	Earnings before Interests, Taxes, Depreciation, Amortization
EEI-ACRM	----------------	Employment Engagement Index – ACRM (Alignment, Capability, Resources, Motivation
EENS-SI	----------------	Estimated Energy Not Supplied for each sustained interruption (MWh)
Σ (EENS-SI)	-------------	Sum of all EENS-SI over a 12 month period (MWh)
ELT	----------------	Executive Leadership Team
ENS	----------------	Energy Not Supplied
EPRI	----------------	Electrical Power Research Institute
EPSRA	----------------	Electric Power System Reliability Assessment
ESS	----------------	Employee Satisfaction Survey
EVA	----------------	Economic Value Added

-- F --

FSI	----------------	Frequency Severity Index

-- G --

GE	----------------	Gender Equity
Gov	----------------	Government
Gs	----------------	Generation

-- H --

HRDSI	----------------	HR Development Strategies & Initiatives
HRSI	----------------	Human Resources Sustainability Index

-- I --

I-ELT	----------------	Information metric to Executive Leadership Team
IEEE	----------------	Institute of Electrical and Electronics Engineers
IFRS	----------------	International Financial Report Standards

-- J --

JWG	----------------	Joint Working Group

-- L --

LTIFR	----------------	Lost Time Injury Frequency Rate
LTIR	----------------	Lost Time Incident Rate

-- M --

MAIFI-CPI	----------------	Average frequency of momentary connection point interruptions per year
MCS	----------------	Medical Care Survey

-- N --

NEL%	----------------	Percentage of non-entry (NEL) positions filled by external applicants
NERC	----------------	North American Electric Reliability Corporation
NPCC	----------------	Northeast Power Coordinating Council

-- O --

OFGEM	----------------	Office of Gas and Electricity Markets
OHSA	----------------	Occupational Health and Safety Act
OHSA-RIR	----------------	Occupational Health and Safety Act, Recordable Incident Rate
OMA	----------------	Operating, Maintenance and Administrative Expenses
OPER-CASH	--------------	Operating Cash: Cash generated before interests
OPEX	----------------	Operating Expenditure

-- P --

PD	----------------	Peak System Demand for reporting year (MW)
PES	----------------	Power Engineering Society
PNS	----------------	Interrupted Power
PS	----------------	Public Stake Holders
PVA	----------------	Preventable Vehicle Accidents

-- R --

RAB	-----------------	Regulatory Asset Base
RE	-----------------	Racial Equity
ROE	-----------------	Return on Equity
RVR	-----------------	Regulated Voltage Ratio

-- S --

SAIDI	-----------------	System Average Interruption Duration Index
SAIFI	-----------------	System Average Interruption Frequency Index
SAIFI-CPI	-----------------	Average frequency of sustained connection point interruptions per year
SAIRI-CPI	-----------------	Average total duration of all sustained connection point interruptions per year
SARI	-----------------	System Average Restoration Index
SM	-----------------	System minutes
SML	-----------------	System Minutes Lost
SMSA	-----------------	Safety Management System Activities
SRSI	-----------------	Information metric to Executive Leadership Team

-- U --

UE	-----------------	Unsupplied Energy

-- T --

T- SAIDI	-----------------	Transmission System Average Interruption Duration Index
T- SAIFI	-----------------	Transmission System Average Interruption Frequency index
THD	-----------------	Total Harmonic Distortion
TRIR	-----------------	Total Recordable Incident Rate
Ts Cont	-----------------	Transmission Continuity
TSO	-----------------	Transmission System Owner
Tx	-----------------	Transmission

-- W --

WACC	-----------------	Weighted Average Cost of Capital
WCF	-----------------	Weighted Capability Factor
WDAFOR	-----------------	Weighted DAFOR
WG	-----------------	Working Group
WPA	-----------------	Work Program Accomplishment

-- Y --

YEC ----------------- Yearly Energy Consumption in the system (TWh)

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