Service Reliability and Regulation in Ontario

By

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Summary
In 1998, Bill 35, the *Energy Competition Act*, was enacted: Ontario's electricity distributors were to be corporatized and recapitalized, and placed under the oversight of the Ontario Energy Board ("OEB" or the "Board"), itself charged with instituting Performance Based Regulation ("PBR"). Some stakeholders held that initial levels of efficiency varied significantly, due to overcapitalized rate bases among some utilities gold-plating their network. In subsequent research I found only about 20 percent of firms were technically and allocatively efficient. The average distributor was about 13 percent less efficient technically than the frontier but about 30 percent less efficient allocatively. Among the least efficient distributors, "gold-plating" was even more notable. However, a consensus prevailed that the province had a reliable system. Ontario distribution industry survey data indicated that the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") for the distributors ranged from about .50 to about 1.5. This performance was significantly better than many European and North American peers.

The OEB instituted minimum reliability standards in its 1st Generation PBR plan set out in the Board's 2000 Electricity Distribution Rate Handbook: for local distribution companies ("LDC") with historical data, reliability was to stay within the range of performance over the prior three-years. The Board noted that it would move to investigate the implementation of more refined standards along with non-performance financial penalties. However, the intentions laid out by the Board in 2000 were not realized. Reliability performance by LDCs was not broached again by the OEB until 2003, and then only to produce a report on regulatory principles underlying just and reasonable rates. Not until 2008 did the Board release even a cursory examination of LDC reliability performance; furthermore, that report announced that the mandated minimum standards implemented in 2000 were not compulsory but voluntary. At the same time, the Board subjected the LDCs to multiple and repeated changes in regulatory governance and rate setting. Notably, the OEB opted to implement rate adjustment mechanisms using benchmarking based substantially on O&M costs and unadjusted for labor capitalization or reliability performance.

Ontario LDCs have experienced a ***deterioration*** in reliability. Clearly some LDCs are ***not compliant*** with the 2000 Rate Handbook standards. For the composite index including Hydro One Inc. results for SAIDI and SAIFI exceed the standard each year. We find deterioration in 2006 - 2008 relative to 2003 – 2005 and in 2003 – 2005 relative to 2000 – 2002. Moreover, 2000 - 2002 reliability has degraded significantly from pre-PBR. It appears that some LDCs have used the worsening performance to implement ***lower targets/standards.***

On August 23, 2010, the OEB enunciated an LDC service reliability consultation to assist the Board in developing the proposed amendments to codes which will establish the system reliability requirements: **Initiative to Develop Electricity Distribution System Reliability Standards (EB-2010-0249).** To that end, the OEB has released a Report on Jurisdictional

Reliability plans prepared by Pacific Economics Group ("PEG").[1] The Board has also released two additional reports covering survey data on customer satisfaction, outage experiences, and willingness to pay ("WTP") prepared by Pollara.[2] In addition the OEB has surveyed LDCs regarding service quality processes.

In terms of the Board's current proceeding, I find the PEG report to be a good overview of jurisdictional service quality regulation ("SQR") practices. I also agree with Dr. Kaufman's recommendation that the Board should view the frameworks developed in Massachusetts, Victoria, and Norway as best practice options given their different approaches to regulating service reliability. Each could be a good model, with Norway representing arguably the "gold standard" in SQR. I also support the Board's efforts to measure customer satisfaction and WTP. It is important to note that the outage experience reported by respondents was worse than these customers were anticipating. Customers anticipated 3.43 outages per year; customers experienced 4.78. Customers anticipated outages would last 1.99 hours; customers experienced outages lasting 2.79 hours. That is, customers experienced 39.4 percent more outages lasting 40.2 percent longer than they expected. Clearly, network reliability is significantly worse than customer expectations. However, a number of issues need to be explored to better understand and more accurately measure satisfaction and WTP.

In the short run, and in the absence of a more robust incentive regime, Ontario distributors' should face financial penalties for non-compliance with mandated minimum reliability standards. In the medium run, the Board should adopt SQR which combine reliability standards with penalty schemes as well as single-customer guarantees with monetary payments for non-performance. The latter guarantees/payments should be based on some robust measure of customer interruption costs. In the long run, my preference is to develop an incentive approach that internalizes the cost of supply interruptions; i.e., within which LDCs recognize O&M, capital, and customer interruption costs. The Board should move toward the implementation of a "socially optimal" level of reliability; not too little, not too much. Such regimes have been successfully implemented by a number of regulators. These efforts have been under way for years and are well documented (see for example Council of European Energy Regulators).

After all, the Board itself stated in 2000 in the Electricity Distribution Rate Handbook that it would be in a position "to set industry service quality performance standards. Once these standards have been established, PBR incentive mechanisms with economic consequences will be introduced around the service quality indicators". The Board has been consistent since that decision that reliability is a critical component of the LDCs' output bundle. Now in 2010, the

[1] *System Reliability Regulation: A Jurisdictional Survey*, Pacific Economics Group, May, 2010.
[2] Pollara, *Electricity Outage and Reliability Study Consumer Component*, September 2010; *Electricity Outage and Reliability Study Business Component*, September 2010.

Board should move to address the question: what is the right level of reliability for the ratepayers of Ontario?

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1.0 Introduction

On August 23, 2010, the Ontario Energy Board ("OEB" or the "Board") enunciated a consultation on electricity distribution service reliability to assist the Board in developing the proposed amendments to codes which will establish the system reliability requirements: **Initiative to Develop Electricity Distribution System Reliability Standards (EB-2010-0249),**

> *Through this initiative the Board intends to establish regulatory requirements that will reinforce and strengthen the responsibility of Ontario electricity distributors to provide reliable delivery of electricity to all Ontario customers. The Board expects that the implementation of system reliability standards as regulatory requirements will support distributor investment planning decisions. As part of the initiative, the Board will consider how the standards may assist the Board in the review of distribution system plans and distributors' rate applications.*

To that end, the OEB has released a Report on Jurisdictional Reliability plans ("2010 PEG Report")[3] prepared by Pacific Economics Group ("PEG"). The Board has also released two additional reports covering survey data on customer satisfaction, outage experiences, and willingness to pay ("WTP") prepared by Pollara[4]. The OEB has also surveyed local distribution companies ("LDC") regarding service quality processes. On October 15, 2010 the Board held a stakeholder conference to discuss issues important to distributors and consumers on the implementation of distribution reliability standards. The Board invites written submission from stakeholders on the research material provided and the set of issues set out by the Board.

In my submission, in addition to providing comment on the research material provided in this consultation and on some of the issues set out by the Board, I provide a historical context around the OEB's service reliability regulation, the distributors' service reliability performance and the distributors' efficiency performance.

1.1 The OEB's Incentive Scheme, Efficiency Ranking, and Reliability

Unlike the total cost benchmarking advocated in 1st Generation Performance Based Regulation ("PBR") for Ontario electricity LDCs, the OEB has implemented an incentive regulation ("IR") scheme that focuses mainly on O&M. This penalizes LDCs that capitalize small amounts of labour or have different production processes that rely more heavily on labour and less on capital.[5] More importantly, no consideration is given in benchmarking LDCs for the differing levels of reliability that the Board itself has documented. The 2008 Board Staff Report finds that anywhere from 25 to 50 percent of Ontario distributors fall below the targets examined and that

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[3] *System Reliability Regulation: A Jurisdictional Survey*, Pacific Economics Group, May, 2010.

[4] Pollara, *Electricity Outage and Reliability Study Consumer Component*, September 2010; *Electricity Outage and Reliability Study Business Component*, September 2010.

[5] Capital intensity ranges from about 40 percent of costs to over 60 percent of costs.

among LDCs which fail to meet their reliability target the reliability performance is 50 to 100 percent worse than the target.[6]

There are costs which must be incurred to maintain service reliability. Some LDCs found to be among the higher cost LDCs may have better reliability than some LDCs found to be among those with lower costs. Yet, these LDCs with better reliability are judged to be less efficient by the Board and are penalized with higher productivity stretch requirements in 3rd Generation IR. LDCs with higher reliability may likely have lower customer interruption costs. The lower interruption costs could well result in lower total costs. Therefore, some LDCs penalized by the Board with higher productivity factors (X), may be budgeting more optimally than low O&M cost LDCs with low reliability that are being rewarded by the OEB with lower productivity stretch factors in 3rd Generation IR.

1.2 The Multi-Dimensional Nature of Distribution Output and Just and Reasonable Prices

Electric distributors produce and sell a multi-dimensional output to their customers. Clearly, the level of service reliability and voltage quality, among other factors, can vary substantially among LDCs, producing different products (i.e. service reliability levels) depending on the mix of characteristics delivered to the customers. These different bundles of characteristics would likely have different costs associated with them, and thus result in differences in distribution rates. In evaluating the reasonableness of a distributor's rates, we need the context of the "whole package(s)" being delivered to its customers. Rates, reliability, and costs must be evaluated simultaneously.

Regulators usually have the responsibility to ensure that regulated prices such as electric distribution rates are "just and reasonable". But, most energy regulators have a dual responsibility toward consumers: they must ensure that prices are just and reasonable and they must ensure the appropriate levels of service reliability are delivered. Without the latter, there can be no assurance that the prices being paid are in fact just and reasonable.

The OEB has itself noted its responsibility with respect to service reliability. In August, 2003, the OEB began a review of service quality regulation ("SQR"). The OEB acknowledged:

> *Section 1 of the Ontario Energy Board Act, 1998 states … The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives: ... 3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.*

[6] Staff Discussion Paper, *Regulation of Electricity Distributor Service Quality*, EB-2008-0001, January 4, 2008.

Subsequently, OEB staff released a discussion paper on service quality ("2003 Staff Report")[7]. Importantly, the 2003 Staff Report reaffirmed the link between service quality and rates: just and reasonable rates must consider the quality of the service provided.

> *Service quality regulation is integral to economic rate regulation, to setting "just and reasonable" rates. From the perspective of the users or customers of the service, there must be a consideration of the "value" of the product or service, where value is defined as the product or service meeting or exceeding the needs and expectations of customers relative to the price charged.*

1.3 Incentives, Costs, and Customer Interruptions

Firms can only optimize costs internal to their cost structure, typically capital and OM&A. Costs borne by customers due to the utility's interruptions are generally not considered by a utility when deciding capital and OM&A budgets. The failure to recognize such customer interruption costs would tend to lead to insufficient spending on reliability.

The shift to IR can put OM&A costs in conflict with the pursuit of profit during the plan's term. Cost reductions experienced earlier in a plan's term are worth more to a utility than cost reductions achieved in later years. Since capital costs may already be committed, they may not be subject to significant changes in the early years of a plan's term. Therefore the utility could be incented to cut OM&A expenses beyond what is prudent for the reliability of the network.

Unjudicious curtailments in OM&A have been shown to significantly lower LDC reliability. Ter-Martirosyan (2003) examined the effects of IR on electricity distributors' OM&A and service quality.[8] The author uses 1993 – 1999 data from 78 major US electric utilities from 23 states. Ter-Martirosyan finds that IR is associated with a reduction in OM&A expenditures and that reduced OM&A activities are associated with an increase in SAIDI. Importantly Ter-Martirosyan's analysis concludes that the incorporation of strict reliability standards with financial penalties into IR can offset the tendency of plans without standards and penalties to result in imprudent cuts in critical OM&A activities.

1.4 Yardstick Regulation, the 2008 Board Staff Report, and Critical Issues for the OEB's Incentive Regulation

The 2008 Board Staff Report calculates sector, rural, and urban averages as well as a number of Board defined peer group averages with varying numbers of LDCs. The 2008 Board Staff Report examines the reliability performance of LDCs relative to various proposed benchmarks such as sector average or peer group average performance over a-three year period. The report

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[7] OEB Staff Report, *Service Quality Regulation for Ontario Electricity Distribution Companies A Discussion Paper*, September 15, 2003.

[8] Ter-Martirosyan, A., *The Effects of Incentive Regulation on Quality of Service in Electricity Markets*, George Washington University Dept. of Economics Working Paper, Presented at International Industrial Organization Conference, North Eastern University, Boston, 2003.

finds that anywhere from 25 to 50 percent of Ontario distributors fail the benchmarks; furthermore, distributors that failed typically have a reliability performance that is 50 to 100 percent worse than their peer group's average. What is clear from the data is that a very wide variation in reliability performance exists among LDCs, even within the Board's peer groups. This finding should elicit significant concern on the Board's 3rd Generation IR for customers experiencing such degraded reliability:

- No explanation is offered for the fact that many customers of low performing distributors are experiencing significantly lower reliability than customers of other distributors with similar operating conditions.
- Are these customers with degraded reliability paying less for their bundle of services?
- Is it possible that some of these same customers are actually being charged more for the service despite the degraded reliability?

Also, recall that the Board undertook its cost comparison for setting 3rd Generation X factors largely in isolation of reliability. But, Board Staff's own analysis in 2008 showed that reliability varied widely within its selected peer groups. Despite these differences in observed reliability among peers, varying IR X factors were set without accounting for the variation in reliability among LDCs. This raises a number of questions:

- When we look at the Board's peer groups, is it possible that some LDCs with degraded reliability had lower O&M costs compared with its peers? Could these LDCs with lower reliability and lower O&M costs have been rewarded by the Board with lower X factors in 3rd Generation IR?
- Is it possible that some of the LDCs that were judged to be less efficient by the Board based on O&M could have had lower customer interruption costs based on their higher reliability?
- Finally, is it possible that some of the LDCs that were judged to be less efficient by the Board which had lower customer interruption costs (based on their higher reliability) could have been operating with a *more socially optimal budget* since their inclusive total costs including customer interruption costs were lower than the inclusive costs of LDCs with lower O&M costs, lower reliability, higher customer interruption costs, and higher inclusive total costs?

If these observations are in fact true, what message is the Board's cost comparison and 3rd Generation IR frameworks sending to the LDCs? Will those LDCs with higher reliability but higher O&M cut costs and degrade service reliability?

1.5 Incentive Regulation and Service Quality Standards

A possible consequence of these perverse service quality results is the common requirement for utilities under IR to have explicit and strict service quality standards, often with penalties for violations. Indeed, Ter-Martirosyan finds that 70 percent of the utilities in the sample with IR had such penalties.

Regulators in both North America and Europe have responded to profit-driven OM&A cuts with new regulatory initiatives. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed mandates on the utilities covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations. In Europe, regulators such as the Council of European Energy Regulators ("CEER") have documented and encouraged the adoption of SQR which combines system-wide standards with incentive/penalty schemes as well as single-customer guarantees with monetary payments for non-performance. Some regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements or interruption avoidance.[9]

The OEB's 1st Generation PBR Stakeholder Implementation Task Force ("Implementation Task Force") concluded that utilities would face increased profit motives under IR. It would not be unreasonable to expect the Ontario utilities to react to these increased incentives. Ultimately the OEB implemented PBR. The Board noted its own concerns and cautions regarding the implementation of First Generation PBR as follows:[10]

> *Any reduction in the quality and/or reliability of a service represents a reduction in the value of that service. Therefore, as part of its function in regard to approving or fixing just and reasonable rates, the Board has a responsibility to oversee that service quality is preserved and improved… the Board favours the minimum standards proposed in the draft Rate Handbook for first generation PBR. The Board notes that these standards represent the minimum acceptable performance; a utility should continue to establish its operating performance at any level better than the minimum standard, taking into consideration the needs and expectations of its customers and of cost implications.*

However, were the OEB's standards, monitoring, and reporting requirements sufficiently robust to mitigate the utilities potentially imprudent cost reductions, and the likely consequences for lowered reliability? Below, I discuss the role of service standards in the OEB's 1st Generation PBR adopted by the Board in 2000 and the Board's processes related to SQR since then. I also

[9] Some regulators have taken WTP information and explicitly incorporated this into their distribution price regulation. One regulator has specified a goal of achieving a socially optimal level of reliability by recognizing that customer interruption costs must be considered.

[10] OEB Decision on PBR for Electricity Distributors, RP-1999-0034, January 18, 2000, pp.50-53.

examine the network reliability of the regulated LDCs over the 2000 to 2007 period and compare it with the 1993 – 1997 performance.

1.6 My Findings

In the mid-1990s Ontario distribution industry survey data indicated that the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") for Ontario municipal utilities ranged from about 0.5 to about 1.5. The Implementation Task Force also collected reliability data from Ontario municipal distributors. Its findings covering utilities with over 80 percent of the distribution customers were similar. In fact, this performance was significantly better than many European and North American peers. My research has also found that during the 1990s the Ontario municipal distributors had a high level of technical efficiency; some, however, were allocatively inefficient, i.e., "gold plated". In 2000, the Board implemented 1st Generation PBR which included mandatory, minimum reliability standards. So, pre-PBR, we find some utilities that have overcapitalized but provided a very high level of reliability. Below we examine the near decade of experience since the passage of the *Energy Competition Act, 1998* and the resulting restructuring of Ontario's distribution sector. How have LDCs and customers fared in this altered regulatory environment? In particular, we examine LDCs' reliability performance.

We find that by 2008 the OEB had altered its position on service reliability regulation: it now professed a non-mandatory, voluntary approach to reliability, not the minimum standards implemented by the Board in its 2000 Decision ("2000 Decision") that resulted in the 2000 Electricity Distribution Rate Handbook ("2000 Rate Handbook"). We find that reliability has declined almost continuously over the 2000 to 2008 period. Over this 9-year period, the sector's reliability degradation has become progressively worse, with results in the middle three years (2003 – 2005) significantly worse than the first three years (2000 – 2002), and the results in the last three years (2006 – 2008) significantly worse than the middle years. It appears that the distributors have not been examined for compliance with the original, mandatory standards. The OEB appears somewhat unique among North American and European regulators in going from a mandatory to voluntary SQR with the implementation of IR; regulators have generally moved to implement stricter standards, many with guarantees and penalties[11].

In terms of the Board's current proceeding, I find the 2010 PEG Report to be a good overview of jurisdictional SQR practices. I also agree with Dr. Kaufman's recommendation that the Board should view the frameworks developed in Massachusetts, Victoria, and Norway as best practice options given their different approaches to regulating service reliability. Each could be a good model with Norway representing arguably the "gold standard" in SQR. I also support the Board's efforts to measure customer satisfaction and WTP. However, a number of issues need to

[11] For a review of European Service Quality Regulation, see the Council of European Energy Regulators, *Third Benchmarking Report of Quality of Electricity Supply*, 2005.

be explored to better understand and more accurately measure satisfaction and WTP. I discuss these below.

2.0 Regulatory Restructuring and Service Reliability Performance in Ontario

Prior to the 1998 comprehensive restructuring of Ontario's electricity sector related to the *Electricity Competition Act, 1998* (the "Act"), over 300 distributors varying in size from several hundred customers to hundreds of thousands of customers operated in the Province. The distributors operated alongside a vertically integrated, provincially owned utility, Ontario Hydro, which owned most of the generation and transmission capacity in the province and distributed electricity in rural areas of the province not served by municipal electric distributors. Ontario Hydro sold electricity at cost to the distributors which then distributed at cost. Due to their non-commercial public status, the distributors were not subject to stringent regulation but had rates set in a light-handed, cost pass-through regulatory approach by Ontario Hydro. The allowed return levels were set by Ontario Hydro's regulatory function but returns varied considerably. Returns were re-invested in the system.

The Act provided for the commercialization of the municipally-owned distributors as well as Ontario Hydro's successor network company, Hydro One Inc. ("Hydro One"). The Act also made the OEB responsible for the regulation of the distributors. Faced with the regulatory responsibility of 300 electricity distributors the OEB initiated a consultation process to structure a suitable PBR framework, which the OEB subsequently implemented in 2000. Some stakeholders, including utilities, held that initial levels of efficiency varied significantly, due primarily to overcapitalized rate bases among some utilities, particularly among distributors in high growth service territories, that collected capital contributions from developers. These stakeholders contended that distributors with high levels of contributed capital distorted their input mix. In subsequent research I found a high level of technical efficiency[12] rising from 87 percent in 1988 to 93 percent in 1997. In terms of cost allocation, i.e., having the right mix of inputs given relative prices, however, the average Ontario municipal distributor was about 30 percent less efficient. For some utilities, the extent of allocative inefficiency was even more notable.[13]

[12] F. Cronin, S. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," *Annals of Public and Cooperative Economics, 78, No.4, 2007.*
Technical efficiency measures the degree to which firms are operating at an optimal output to input ratio, given the set of inputs selected by the firm. In this case, by 1997, the average Ontario MEU was only 7 percent lower than the most efficient, best practice utilities, i.e., if the average firm were to operate as efficiently as the most efficient MEUs, the average MEU would be able to raise its output only 7 percent with inputs held constant.
[13] F. Cronin, S. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," *Annals of Public and Cooperative Economics, 78, No.4, 2007.*

The Implementation Task Force noted the dilemma involved in moving to PBR.[14] While a utility would face greater incentives to eliminate embedded inefficiencies likely accumulated under cost of service ("COS"), the regulator could not easily quantify the potential level of allocative inefficiency.[15] Some participants pointed to the "yardstick competition" being implemented in the UK, Europe, and Australia and argued that such models should be adopted.[16]

Unlike efficiency levels, a general consensus prevailed that the gold plating, if a fact, had produced a near ubiquitous, highly reliable system. Two common industry standards for measuring network performance are the SAIDI and the SAIFI.[17] On both measures, Ontario utilities' performance was notable. The Implementation Task Force recognized that implementation of SQR is a key aspect of PBR to ensure that service reliability is not compromised in the pursuit of higher profits.

2.1 The Pre-PBR Reliability of Ontario Electric Distributors

What was the reliability of Ontario distributors in the mid to late 1990s prior to the start of the OEB's PBR? We have two sources of data to examine this question. One set of data from the industry was published as far back as the early 1990s[18]. A second set of data was collected by the OEB's Implementation Task Force in 1999.

Since 1990, the former Ontario Municipal Electric Association ("MEA") collected and published composite performance metrics from its members, including reliability indices. The results were based on data from almost all large and medium sized utilities, collectively serving 75 – 85 percent of customers in the province. Exhibit 1 presents the 3 and 5-year averages on SAIDI and SAIFI. For the former, we see that SAIDI averaged 1.23 in the 3 years prior to the PBR, with the top quartile averaging 0.32. For SAIFI, the average is 1.49 with the top quartile at 0.34. The 5-year average results are similar.

[14] See Report Of the OEB, *PBR Implementation Task Force*, May 1999, at: http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/implemnt.pdf

[15] Because they were not for profit the earned returns were reinvested to avoid debt, rather than returned as rebates to customers. That was the decision of local commissions who took pride in having a debt-free utility. Commissioners were either publicly elected reps or appointed by the city**.**

[16] Subsequently, we examined PBRs implemented in the U.K., Australia and Europe. These PBRs generally benchmark on partial costs and examine only a minority of inefficiency. They create sizeable distortions in efficiency rankings: *individual utilities could experience errors in rankings of 20, 30 or even 40 percent.* See F.J. Cronin & S.A. Motluk, "Flawed Competition Policies: Designing Markets with Biased Costs and Efficiency Benchmarks," *Review of Industrial Organization*, Vol.31, No. 1, Aug 2007.

[17] The two reliability indicators used universally are SAIDI and SAIFI. SAIDI is the average duration of a system outage calculated by adding the number of customer-hours of interruptions and dividing by the number of customers. SAIFI is the average frequency of outages and is calculated by adding the number customer interruptions divided by the number of customers.

[18] MEA, Performance Management Ratios 1993 – 1998 Composite Results, August, 1998

Exhibit 1. Service Reliability Pre-PBR for Ontario Municipal Distributors*

	3-Year Average		5-Year Average
SAIDI			
Mean	1.23		1.20
Top Quartile	0.32		0.42
SAIFI			
Mean	1.49		1.51
Top Quartile	0.34		0.54

******Performance Management Ratios 1993 – 1998 Composite Results***, MEA, August, 1998**

During the development of its 1st Generation PBR, the OEB's Implementation Task Force undertook several surveys of the distributors, including reliability performance. Responses from over 60 utilities serving 81 percent of customers provided annual data on reliability. Exhibit 2 presents the mean 3-year average for SAIDI and SAIFI. In addition, I have computed the upper-bound benchmark which was selected by the Board as the performance standard: distributors were to operate within their performance boundary in the previous 3 years.

I have presented these results for municipally-owned distributors or LDC's as well as for a composite index of LDC's and Hydro One. For LDCs the mean for SAIDI is 1.22 and the mean for SAIFI is 1.46. These results are quite consistent with those presented in Exhibit 1**.** For SAIDI the average 3-year high is 1.59; for SAIFI, the average 3-year high is 1.84. The composite results for SAIDI is a mean of 2.07 with an upper bound of 2.53. For SAIFI, the composite mean is 1.36 with an upper bound of 1.75.

Exhibit 2. Service Reliability and Pre-PBR Standards for Ontario Distributors*

	Municipal	Composite
SAIDI		
Mean	1.22	2.07
Mean Upper Bound Standard	1.59	2.53
SAIFI		
Mean	1.46	1.36
Upper Bound Standard	1.84	1.75

***Service Reliability Survey conducted by the Ontario Energy Board, *PBR Implementation Task Force*, May 1999.**

In the 2000 Rate Handbook[19], the Board spelled out the reasons for regulating service quality performance.

[19] OEB, 2000 Electricity Distribution Rate Handbook: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/First+Generation+PBR+Distribution+Rate+Handbook

> *PBR provides the electricity distribution utilities with incentives for economic efficiency gains. To discourage utilities from sacrificing service quality in pursuing these economic incentives, service quality performance measures are included in the PBR plan. Utilities will be expected to monitor and report on all of the service quality indicators included in the plan. The performance of individual electricity distribution utilities will be made publicly available…*

Initial standards were minimum requirements performance levels: for the LDCs that had historical data, which were the LDCs that served the majority of the customers in Ontario, they were to keep their service reliability indices within the range of performance over the prior three-years. As soon as feasible, all LDCs would collect such data. And, the Board would investigate the implementation of more refined standards along with financial penalties for not meeting these standards.

2.2 Post Restructuring Reliability Performance

So, pre-PBR, we find distributors that have generally overcapitalized their network but provided a very high level of reliability. How have LDCs and customers fared in this altered regulatory environment?

Starting in 2000, the Board required the distributors to report monthly reliability data as stipulated in the 2000 Rate Handbook, annually. I have examined the reliability data filed by the 80 to 100 LDCs over the 2000 to 2007 period to judge whether the 2000 through 2003 data is consistent with 2004 through 2006 and have found no systematic deficiency in the data. First, I performed a general casual comparison of reported values for each LDC. Second, multiple tests were conducted to gauge if the distributions were normal. Additional parametric and nonparametric tests were conducted. My conclusion: that all years of data from 2000 to 2007 come from the same population. The 2001-2007 data therefore can be used as a single set of data. I have examined this data in detail. There are some minor issues that are common to all data collection processes, such as duplicate records, missing data, and occasional entries that appear inconsistent, e.g., monthly data reported at annual rates. These cleanup items occur more frequently for some of the very smallest LDCs many of which were subsequently acquired by other distributors. However, all of these issues are easily resolved.[20]

Exhibit 3 presents the Ontario composite SAIDI. We see that the two earliest years, 2000 and 2001, have two of the three lowest recorded values. The last three years have the two highest values. Note in particular that on a composite level, the 2003 – 2005 period has *two years which exceed* each year in the initial 2000 – 2002 period; and, that the 2006 – 2008 period has *two years which exceed* each year in the 2003 to 2005 period. In comparing the initial 3-year period 2000 – 2002 with the pre-restructuring average covering the 1993/94 – 1997/8 period we can see

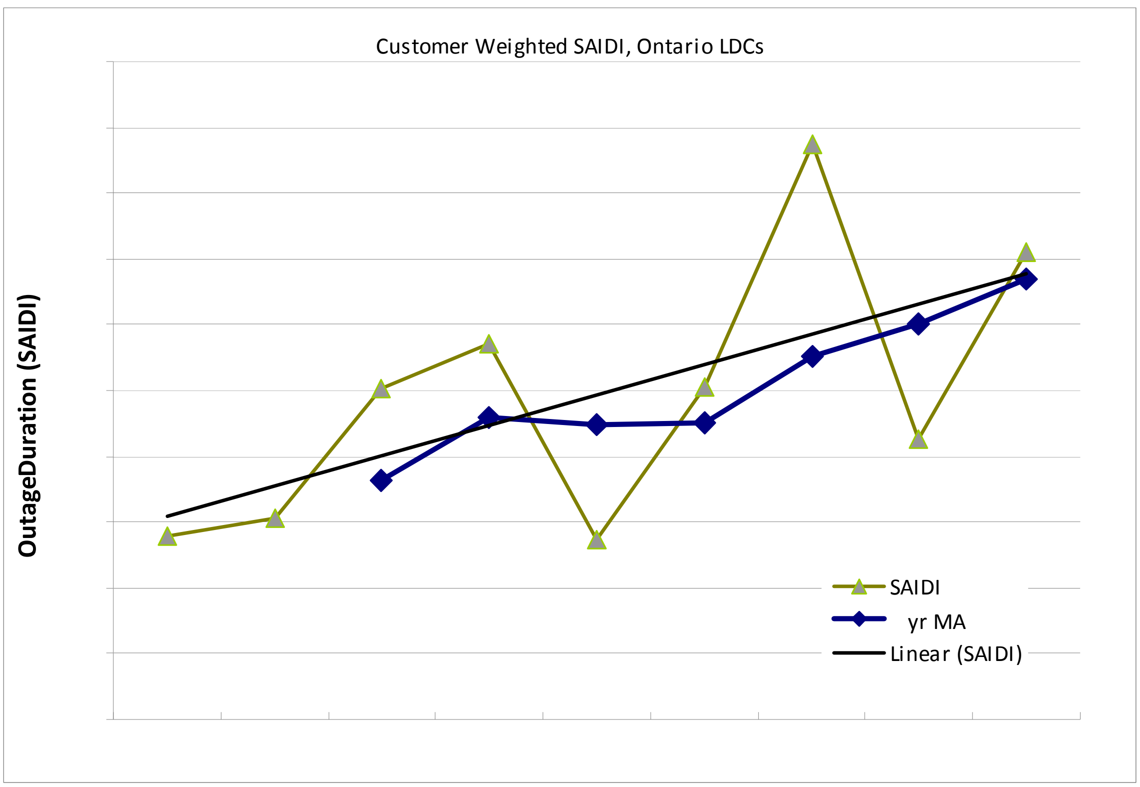
[20]Missing data etc., also occur in the 2002-2006 data the Board used for its cost comparison and benchmarking.

that the post-restructuring average in the initial period 2000 – 2002 of 3.63 is notably higher than the pre-restructuring average of 2.06.

Exhibit 3 also presents a SAIDI trend line based on an estimated regression. *The slope of the trend line is notably positive at about a 30 degree angle*. I have used a back-cast of the trend line to "predict" the value in 1998.[21] The 1998 value at 2.18 is very close to the 5-year pre-restructuring average of 2.06. The trend line value for 2000 is 3.1; the trend line value for 2008 is 6.8. Thus, the trend line, which de-emphasizes the extreme data points, indicates that the 2008 trend line point is 119.4 percent higher than the 2000 trend line point. *Both the actual reliability data and the estimated trend line clearly show a pervasive degradation of service reliability on a composite level over the 2000 – 2008 interval.*

The data also show an even more significant degradation compared with the trend exhibited in the 1993/4 to 1997/8 period. The composite post-PBR results significantly exceed the pre-PBR average of 2.07 in each year. The final 3-year average is 6.70: three times higher than the pre-PBR average. Results in each year also exceed the upper bound standard by a wide margin. This strongly suggests that the Board's SQR has not been effective.

Exhibit 3. Outage Duration (SAIDI), Linear Trend, and Three-Year Moving Average



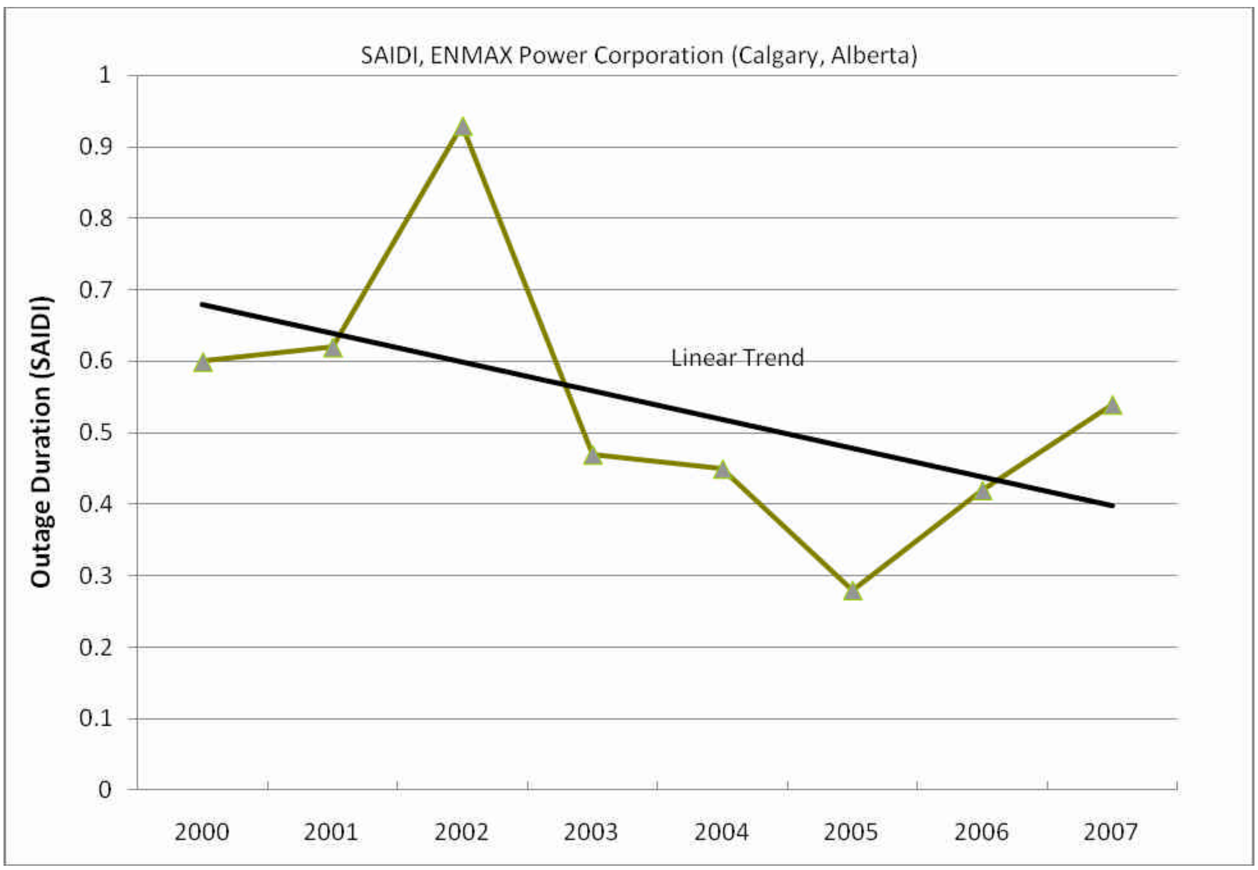
Source: Ontario Energy Board annual PBR filings. Author calculations.

[21] That is, an extrapolation into the past based on the estimated trend line.

For comparative purposes, I have included the SAIDI performance of another major Canadian LDC, ENMAX of Alberta. Interestingly, as revealed in Dr. Kaufman's jurisdictional analysis, ENMAX is one of two Canadian LDCs subject to a penalty-reward SQR framework.[22] Let's see how its reliability has fared since 2000.

As Exhibit 4 shows, the initial SAIDI value is about .60 hours. Values generally range between .30 and .60 hours. The linear trend is negative, indicating that reliability performance has tended to improve over the period even though the initial SAIDI value was about .60 hours. This performance is similar to that reported by Ontario LDCs over the mid 1990s. Recall, that over the mid-1990s period, Ontario LDCs reported upper quartile SAIDI levels of .32 to .42 while the mean ranged from 1.20 to 1.23. ENMAX's performance would place it generally in the 2nd quartile of Ontario LDCs mid-1990s performance.

Exhibit 4. ENMAX Outage Duration (SAIDI) and Linear Trend



Source: AUC Proceeding ID. 12, Exhibit 148, New UCA IR 17, Attachment.

[22] OEB, Stakeholder Conference, October 15, 2010.

In a November, 2009 article in *Public Utilities Fortnightly*, Larry Kaufman, concludes that comparisons involving post-2000 reliability data with earlier performance are not valid[23]. He contends that the methods used by OEB staff to evaluate service quality involving the examination of reliability measures over a three-year period, 2004 – 2006 only generally will yield more accurate inferences on underlying performance than an approach of comparing reliability between more distant points in time such as the comparison I make above. Therefore, I examine SAIDI for the three-year periods since 2000 and present results in Exhibit 5**.**

Exhibit 5. Ontario Composite SAIDI Values: 2000 – 2008 (annual hours per customer)

	Average 2000-2002	**Average 2003-=2005**	**Average 2006-2008**
SAIDI 3-Yr Average	3.63	4.50	6.70

Source: Ontario Energy Board annual PBR filings. Author calculations.

As we can see in Exhibit 5, the 3-year average for 2000 – 2002 is 3.63; the 3-year average for 2003 – 2005 is 4.50; and, finally, the 3-year average for 2006 – 2008 is 6.70. We see that the second 3-year average is 24 percent higher than the first; the third 3-year average is 49 percent higher than the second 3-year average and 85 percent higher than the first 3-year average. Following Dr. Kaufman's suggestion we find notable and steady degradation in the three-year averages over the 2000 to 2008.

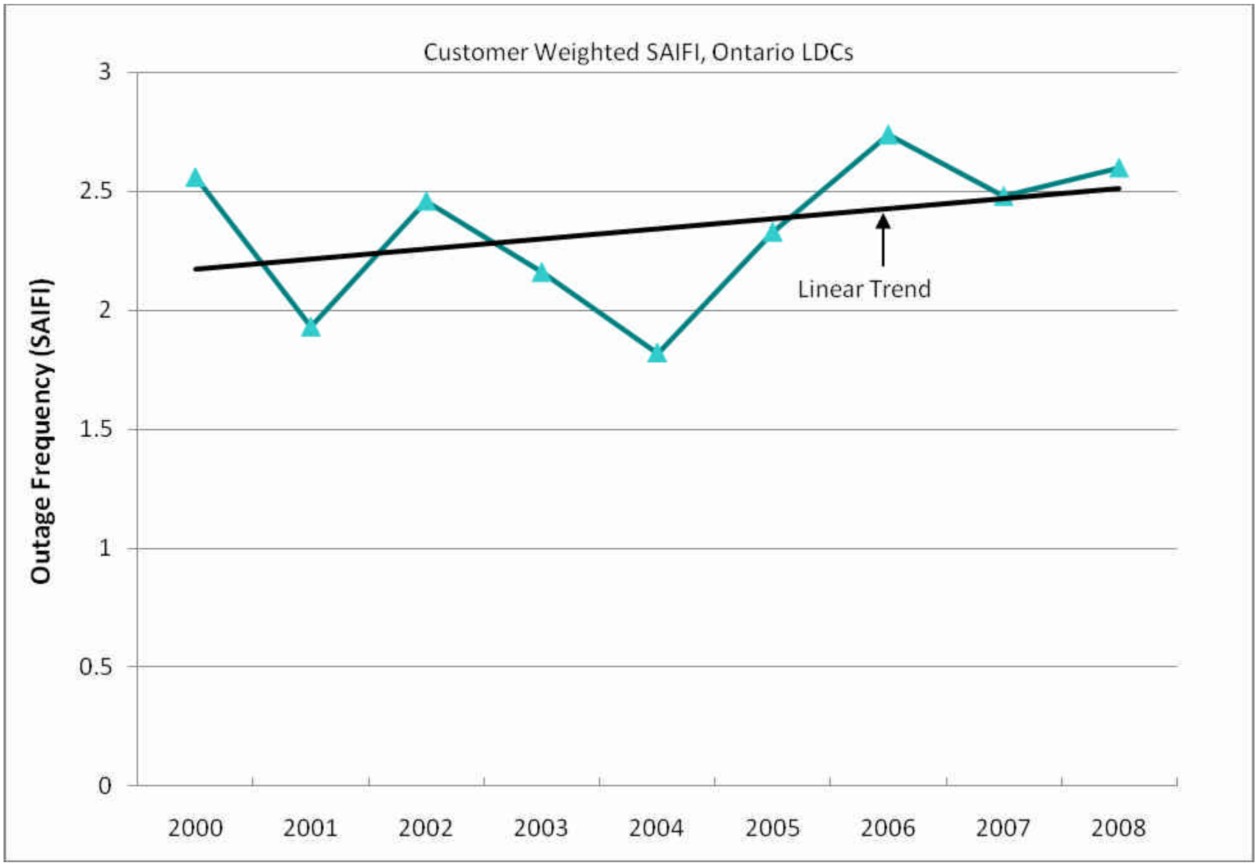
Results for the composite SAIFI are presented in Exhibit 6. Compared with the pre-2000 performance, the Exhibit displays significant degradation. The post-PBR municipal SAIFI average for each year except one exceeds the pre-PBR average of 1.46. In 4 years, the weighted average exceeds the upper bound standard of 1.84. The composite post-PBR results significantly exceed the pre-PBR average of 1.36 in each year. The post-PBR average of 2.31 exceeds the pre-PBR average by 70 percent. The final 3-year average of 2.52 exceeds the pre-PBR average by 85 percent.

What about the upper bound standard? Results in each year exceed the upper bound standard by a wide margin, in some cases by more than 50 percent.

Note also the degradation during the 2000 to 2008 period. The linear trend has a positive slope, indicating that reliability is worsening over the 9 year period. The linear trend is influenced by the higher values in the final three years as opposed to the generally lower values in the earlier years.

[23] Kaufmann, L., Regulatory Reform in Ontario: Successes, shortcomings and unfinished business, *Public Utilities Fortnightly*, November 2009, p.59.

Exhibit 6. Outage Frequency (SAIFI) and Linear Trend



2.3 Post 2000 Turbulence, Governance and Incentives

The intentions laid out by the Board in 2000 for a review of its SQR were not realized. Reliability performance by LDCs was not broached again by the OEB until 2003, and then only as a stakeholder process which produced a report on regulatory principles underlying just and reasonable rates, not an empirical investigation to address the 2000 Decision[24].

Since its regulation of the LDCs, the OEB subjected the LDCs to multiple and repeated changes in regulatory governance and rate setting, some emanating from government policy, that greatly heightening the operational and financial uncertainty for the utilities. In particular, the OEB's shift from the intended total productivity/total cost benchmarking in the 1999-2000 period to a narrow focus on benchmarking O&M expenditures, unadjusted for differing levels of labour capitalization and reliability performance, which greatly increased the possibility of unintended consequences.

[24] OEB, RP-1999-0034, Decision with Reasons, January 18, 2000

Recent research in the U.K. and Poland found allocative inefficiency increased under IR, especially when LDCs faced comprehensive controls, including reliability and line losses: utilities were simply not reacting to the correct price signals, e.g., under valuing the loss of load to customers.[25] Assuming the OEB was unaware of the extent of allocative inefficiency among some utilities, it would not be surprising if the past decade's neglect has worsened the allocative inefficiency as well as reliability of the distributors. Worse, the fixation on O&M costs incents further perverse behaviour by distributors. First, benchmarking predominantly based on O&M costs leads to greater allocative inefficiency. Second, since lower O&M costs would raise benchmarking scores and their revenues (even if the lower O&M costs are a figment of accounting differences), LDCs would be incented to cut O&M. Third, absent SQR, LDCs could cut O&M enough to degrade reliability. All of these changes occurred within a governance environment that was markedly different from that in which the distributors operated pre-industry restructuring.

In his November article, Dr. Kaufman points to other factors to explain degradation in reliability.[26] According to Dr. Kaufman, the worsening reliability is either due to "technology" that better measures reliability or "weather conditions" which "can fluctuate wildly from year to year." In the former case we would conclude that historically reliability has always been as bad as it is now. In the latter case, we would conclude that weather conditions have worsened continually year after year rather than fluctuating "wildly from year to year". While both technology and weather further impact the service reliability reported, given the trends that I identified above, they are unlikely the only factors or even the major factors. I review the issues of technology and weather further, following a review of the Board's experience with SQR.

3.0 The OEB's Experience with Service Reliability Quality Regulation

The OEB's experience with SQR of electric distributors has its origins in the OEB's 2000 Rate Handbook. In terms of SQR, this document was largely based on the Implementation Task Force Report's[27] recommendations.

As indicated earlier, survey work by the Implementation Task Force found that over 60 large and medium utilities covering over 80 percent of customers had been collecting historical reliability data. However, some smaller utilities, some with only hundreds of customers did not have historical data. The "standards" for service reliability for those LDCs with historical data, is to

[25] Cullmann., A. & Hirschhausen., C.V., (2006), From Transition to Competition – Dynamic Efficiency Analysis of Polish Electricity Distribution Companies, Working paper, Dept. of International Economics, DIW Berlin, May 24, 2006. Yu, William, et al, "Incorporating the Price of Quality in Efficiency Analysis: the Case of Electricity Distribution Regulation in the UK," July 2007.

[26] Kaufmann, L., Regulatory Reform in Ontario: Successes, shortcomings and unfinished business, *Public Utilities Fortnightly*, November 2009, p.59.

[27] *Report of the OEB Performance Based Regulation Implementation Task Force,* May 18, 1999.

keep their performance within the range of whatever it had been during the preceding three years. The Implementation Task Force suggested that "The OEB will review the PBR submissions to ensure compliance with the established benchmarks." Those LDCs without reliability data should begin to collect data. The Implementation Task Force recommended that the latter utilities' benchmarks be set by using peer group averages.

However, despite the reluctant acceptance of the "lowest common denominator" for SQR by the Implementation Task Force, the general expectation was that the Board would move quickly, possibly even early in the First Generation, but no later than the beginning of the Second Generation following the initial three-year PBR term, to set reliability performance targets based on a more reasoned and judicious rationale than "just do whatever it was that you were doing."

Indeed, the principles of just and reasonable rates would require that service quality and reliability standards be explicitly formulated as part of the rates charged by distributors to customers. And, the Board itself stated its intent to move expeditiously: "upon review of the first year's results, the Board will determine whether there is sufficient data to set thresholds to determine service degradation for years 2 and 3."[28]

3.1 2000: The 2000 Rate Handbook and Service Quality Regulation

In its first 2000 Rate Handbook the OEB spelled out the reasoning behind the service quality guidelines:

> *…the Board's approach to encourage the maintenance of service quality during the first generation PBR plan is to apply minimum standard guidelines for customer service indicators, and to apply a utility's historic performance as its specific service reliability standards. Where a utility has not monitored service reliability in the past, it is required to initiate monitoring and reporting of the indices. (7-2)*

Thus for SAIDI and SAIFI:

> *All planned and unplanned interruptions of one minute or more should be used to calculate this index. Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance. (7-6, 7-7)*

With respect to service degradation and remedial action, the Board noted:

> *In the absence of historical service quality data, it is not possible to identify service degradation during the first year of the PBR plan. However, upon review of the first year's results, the Board will determine whether there is sufficient data to set thresholds to determine service degradation for years 2 and 3. When established, the Board will issue these thresholds and any utility whose performance falls below these thresholds will be required to file a remedial action plan. (7-10)*

[28] OEB, Service Quality, 2000 Electric Distribution Rate Handbook, March 9, 2000, pp.7-10.

It is anticipated that by the second generation PBR plan, there will be sufficient data collected to set industry service quality performance standards. Once these standards have been established, PBR incentive mechanisms with economic consequences will be introduced around the service quality indicators. (7-10)

However, as noted earlier, this work was not undertaken.

3.2 2003: OEB Working Group on the Review of Service Quality Regulation

The OEB noted its responsibility with respect to service reliability as well as the necessity to evaluate prices hand-in-hand with the actual service reliability delivered to customers. In August, 2003, the OEB began a review of SQR. The OEB noted that:

Section 1 of the Ontario Energy Board Act, 1998 states … The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives: ...

3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

Furthermore, the Board noted that the issues of distribution prices and service quality are integrally linked together: "… a determination of just and reasonable rates must take into account the adequacy and level of service quality….".

The Board's notice with regard to the 2003 service quality initiative issued in August 2003 reviewed the Board's specification of service reliability indicators in its decision on 1st Generation PBR (RP-1999-0034). Addressing the standards, the notice said:

For most SQIs, the Board approved initial minimum standards. The Board determined that other aspects of service quality regulation, including remedial action and/or financial consequences of service degradation, should be considered, but that a proper assessment… required experience with the measurement and reporting of the SQIs.

The notice discussed recent developments regarding Second Generation PBR:

…the Board advised stakeholders of the planned phased development of a second-generation PBR ("PBR II") plan. A review of currently reported service quality indicators and associated standards, as well as consideration of other indicators and elements of service quality regulation, were identified as one of the components of PBR II plan development….As electricity distributors have been reporting their service performance for three years now, the Board considered it timely to review the SQIs and to further develop service quality regulation applicable to electricity distributors….

The notice listed the issues for review: review of the existing service quality indicators; consideration of additional or replacement indicators; the frequency and the periodicity of reported performance; defining degraded service and regulatory responses to service degradation (remedial action reports, possible financial consequences); urban/rural, large/small, etc distinctions in reporting or standards; and, the form and purpose of service quality audits in a comprehensive SQR plan (remedial plans and/or financial rewards and/or penalties).

Subsequently, OEB Staff released the 2003 Staff Report. Importantly, the 2003 Staff Report reaffirmed the link between quality and rates: just and reasonable rates must consider the quality of the service provided:

> *Service quality regulation is integral to economic rate regulation, to setting "just and reasonable" rates. From the perspective of the users or customers of the service, there must be a consideration of the "value" of the product or service, where value is defined as the product or service meeting or exceeding the needs and expectations of customers relative to the price charged.*

The 2003 Staff Report noted that under COS regulation firms' economic incentives were not at odds with the provision of service value since they earn a return on investments and prudent and necessary costs are passed along to the customers. The 2003 Staff Report noted that under COS the review was usually annual, and embedded a review of service quality:

> *…Such reviews occurred periodically – often annually. Service quality could be reviewed as part of the revenue requirement and rate application, with consideration of how existing operational expenses and planned capital investments would contribute to the maintenance or improvement of service quality. Poor service quality could also be a factor considered by the regulator in reducing the allowed revenue requirement (without exacerbating the situation by the utility cutting costs and services in response to reduced revenues)…Also, the "rate base" concept of CoS regulation, some argue, provides an incentive for the firm to overinvest and provide "gold-plated" service, and so service degradation is thus seen as less of a risk under CoS regulation.*

Commenting on PBR, the 2003 Staff Report noted that differing incentives might result in cost containment degrading service. Under PBR, Board Staff noted a greater need for ongoing monitoring of service performance:

> *..PBR differs from CoS in that it provides incentives for a firm to improve its productivity …Another advantage to PBR is…less frequent detailed reviews… With less frequent detailed reviews, there is an increased need for ongoing monitoring of service performance, to ensure that any problems that do occur are addressed…Also, the incentives inherent in PBR…could result in …degraded service. Service quality monitoring serves as a counterbalance to ensure that adequate service is maintained…In some PBR plans… the service performance of the firm may be a parameter affecting rates ... In other plans, aggregate penalties, or the existence of service guarantees and rebates, link the firm's financial performance to its service performance…*

Following the issue of the 2003 Staff Report, the OEB did not take further action on SQR until 2008.

3.3 2008: 2008 Board Staff Report, Regulation of Electricity Distributor Service Quality

The Board described the 2008 Board Staff Report as an initial step in a consultation process designed to assist the Board in determining an appropriate set of electricity distributor service quality requirements. The 2008 Board Staff Report stated *(p.3):*

> *The Board has concluded that it will implement a "standards approach" to service quality regulation. Under the "standards approach", compliance with the performance standard is mandatory and can be enforced through the Board's compliance process.*

However, the paper did not propose standards for service reliability. While Board Staff acknowledged that system reliability is critical for customers (p.30), Board Staff proposed that the original reliability indicators not become mandatory at the present time but be retained in a modified form for monitoring and reporting purposes (p. 23). This is a change from the guidelines provided in the 2000 Rate Handbook referenced above that stated that the distributors should remain, at minimum, within the range of their 3 year historic performance.

The 2008 Board Staff Report was, according to Board Staff, based on a review of other jurisdictions and found a greater incidence of monitoring than of service quality targets/standards or incentives. However, no data or analysis was offered to support this statement. In fact, this conclusion would seem to be somewhat at odds with the 2010 PEG Report. The report details that of 45 jurisdictions in North America that have some oversight of service reliability, 25 have either targets or penalties/rewards embedded in their frameworks.[29] In Australia/New Zealand six of nine jurisdictions have either targets or penalties/rewards. Clearly, many jurisdictions worldwide have adopted SQR incentives and/or standards.

In fact, in an October 2007 report on Electricity Distribution Quality of Service, OFGEM states:

> *Ofgem considers quality of service to be one of its key priorities in network regulation…2006/07 was the fifth year that the DNOs [Distribution Network Operators] faced financial incentives on their quality of service performance…*[30]

In addition to the U.K., incentive-based SQR exists in many other European jurisdictions, and in jurisdictions like Australia. For example, the CEER noted in its 3rd Benchmarking Report on the Quality of Electricity Supply (2005):

> *…Price-cap regulation without any quality standards or incentive/penalty regimes for quality may provide unintended and misleading incentives to reduce quality levels. Incentive regulation for quality can ensure that cost cuts required by price-cap regimes are not achieved at the expense of quality….The increased attention to quality incentive regulation is rooted not only in the risk of deteriorating quality deriving from the pressure to reduce costs under price-cap, but also in the increasing demand for higher*

[29] *System Reliability Regulation: A Jurisdictional Survey*, Pacific Economics Group, May, 2010.
[30] Ofgem, 2006/07 Electricity Distribution Quality of Service Report, Oct 31, 2007, p.1.

> *quality services on the part of consumers…. a growing number of European regulators have adopted some form of quality incentive regulation over the last few years.31*

The January, 2008 letter from the Board also states:

> *Until ...the sector gains experience with any new or modified service quality indicators or requirements, it is in the Board's view premature to move to an incentive approach.*

The Board has been collecting reliability data for a decade; more than sufficient time to gain experience. Indicators such as SAIDI and SAIFI are Institute of Electrical and Electronics Engineers ("IEEE") standards and are used for monitoring and regulating service quality around the world. These indicators have been used by Ontario's electricity distributors' association for at least 15 years; for individual LDCs much longer.

The 2008 Board Staff Report offers a cursory analysis on reliability for 2004 - 2006. This analysis calculates sector, rural, and urban averages as well as Board peer group averages. The 2008 Board Staff Report does examine the reliability performance of LDCs relative to various proposed benchmarks such as sector average or peer group average performance over the last three years. It is unclear whether these averages are simple arithmetic averages across reporting distributors, or a weighted average.

In any case, ***the 2008 Board Staff Report finds that anywhere from 25 to 50 percent of Ontario distributors fail the benchmarks; furthermore, distributors that failed typically have a reliability performance that is 50 to 100 percent worse than their peer group's average.*** What is clear from the data is that a very wide variation in reliability performance exists among LDCs, and even within the Board's peer groups. This finding should elicit significant concern on the Board's part for the customers experiencing such degraded reliability. No explanation is offered on the fact that many customers of low performing distributors are experiencing significantly lower reliability than customers of other distributors with similar operating conditions

What about performance over the whole period since the Board's inception of IR in 2000? Despite the fact that the Board has repeatedly stated that reliable service is necessary for just and reasonable rates, the 2008 Board Staff Report sheds no light on whether individual distributors are in compliance with the reliability guidelines established by the Board in 2000.

The Staff analysis is based on reliability data for 2004 - 2006 only. The 2008 Board Staff Report indicates:

> *The following information is based on the reliability data filed under the RRR for the three years 2004 - 2006. Because the data reported in the earlier years may not have been reported consistently or calculated properly, staff has removed any statistics that appeared to be unreliable. This approach may result in a slightly less than completely*

[31] CEER, Third Benchmarking Report of Quality of Electricity Supply, 2005, p.31.

> *precise and comprehensive analysis, but staff believes that the analysis based on this more selective data represents a more accurate picture of general trends.*[32]

Performance data collected by the same utilities for at least 15 years had been reported to the Implementation Task Force in 1999 and to the Board in its required filings since 2000. In choosing to reject the use of its own pre-2004 data, the Board has missed degradation in 2004–2006 compared to 2000–2003. In addition, it misses an earlier and equally apparent degradation in 2000–2003 compared to the pre-IR period. The Board does not describe the statistical tests that it performed to determine that the pre-2004 data had not been reported consistently or calculated properly nor to remove statistics that appeared to be unreliable.

3.4 2010 Initiative to Develop Electricity Distribution System Reliability Standards

In May 2010, the Board released the survey report on jurisdiction reliability practices (2010 PEG Report). The PEG Report is a good overview of SQR practices. I agree with Dr. Kaufman's recommendation that the Board should view the frameworks developed in Massachusetts, Victoria, and Norway as best practice options given their different approaches to regulating service reliability. Each could be a good model, with Norway representing arguably the "gold standard" in SQR.

4.0 Causes of Reliability Degradation

The reliability indexes that the electricity distributors have been reporting to the OEB indicate significant service degradation in the province over the past decade. It is critically important to disentangle the technical information and examine this degradation and the policy reason(s) behind it. In terms of disentangling the data, we need to understand whether the causal factors are under the control of the distributor or whether it represents loss of supply. I discuss this issue further below.

4.1 Policy Explanations

Possible policy explanations related to the service reliability degradation include:

- Forced distributors' budget cuts because of insufficient revenues under IR and unrealistic expectations on the part of shareholders regarding their dividend payments to shareholders.
- The lack of SQR: no standards and no incentive/penalty prompted distributors' to reduce priority attached to reliability.

[32] Staff Discussion Paper, *Regulation of Electricity Distributor Service Quality*, EB-2008-0001, January 4, 2008, fn 7., p.25.

- Changes in priorities for management and owners as a result of the unstable policy environment that has resulted in significant increased responsibilities and new costs for the distribution sector.
- The change in governance from locally controlled and locally focused, power at cost distribution to full commercial status.
- The incentives of costs versus reliability embedded in the Board's predominantly O&M focused IR has resulted in the predictable outcome found in other jurisdictions and academic research. In this case, the incentive will be strengthened by the 3rd Generation IR framework's productivity stretch factor based on predominantly O&M cost ranking.

As indicated in Chapter 2, Dr. Kaufman[33] postulates that the higher SAIDI and SAIFI levels may be either due to "technology" (i.e., not actually worse reliability, just better measurement of reliability) or "weather conditions" which "can fluctuate wildly from year to year".

4.2 Impact of Technology Upgrade

Dr. Kaufman states:

> *In 1991, few if any utilities used automated measurement systems to record reliability data. Now, automated systems are more widespread and becoming more common every year. Inevitably, when distributors switch from manual to automated systems, they find their measured frequency and duration of outages increase… The fact that distributors increasingly rely on automated outage management systems probably accounts for a significant share of the measured increase in SAIFI and SAIDI over the 1991 through 2007 period. To the extent this is true, these increases are evidence only that reliability is being measured more accurately rather than declining*[34]

In 1999 when the Implementation Task Force surveyed the distribution utilities regarding reliability data collection approximately 60 utilities representing over 80 percent of Ontario customers responded to the survey. About half of these utilities indicated that their network had SCADA capabilities, including some small utilities. These capabilities were present for at least one utility as far back as 1978. For example, a "milestones" highlighted on Enersource's website for their "90th birthday" states "New state of the art SCADA system activated in 1992." In fact, at the 2001 IEEE conference in Atlanta on Lightning Caused Distribution outages the IEEE relied on an Ontario Hydro Reliability Study (1989-1992). The study used data from Ontario Hydro's Failure and Interruption Reporting System. This was subsequently replaced by the Distribution Incident Reporting System.

In response to the Implementation Task Force's survey, a number of utilities reported having 10 years of reliability data. It should also be noted that many utilities provided reliability data to

[33] Kaufmann, L., "Regulatory Reform in Ontario: Successes, shortcomings and unfinished business," *Public Utilities Fortnightly*, November 2009, p.59.
[34] Kaufmann, p.59.

both the Canadian Electricity Association and the Ontario MEA for many years, if not decades, as input to those organizations' reliability numbers. While technology may be a factor that should be considered in analyzing the results, given the state of reliability data collection in the mid-to-late 1990s, it is difficult to conclude that this data is entirely incomparable with data collected post 2000. It is certainly a stretch to conclude that the increase in reported hours of outages from the mid 1990s of about 2.06 for SAIDI to the 5.7, 7.4 and 8.7 data in 2000 and beyond is due largely to technology change. At minimum, given the scope of the change in the reported SAIDI levels, the data detail a downward trend in reliability performance. Recall that the outage data is customer weighted, so the new systems would have to have been installed by numerous large LDCs in recent years to make the earlier data incompatible with the later data.

4.3 Impact of Weather

Dr. Kaufman notes that weather can affect reliability:

> *These variables include such weather conditions as strong winds, storms, lightning, and extreme heat and cold. Not only do these weather conditions have a substantial impact on measured reliability, but they can fluctuate wildly from year to year. Since measured reliability often is impacted by volatile and unpredictable weather variables, caution always must be exercised when making simple reliability comparisons across two points in time*.[35]

Undoubtedly, weather plays a role in the level of reliability statistics reported and caution must always be exercised in making simple reliability comparisons across two points in time. However, there are reasons why the reliability trends indicated by the data cannot be ignored as being significantly weather related.

First, we are not "making simple reliability comparisons across two points in time."

Second, to ignore the reliability trends indicated by the data as being substantially weather related assumes that weather conditions would have worsened continually year after year after year, i.e., that weather is a non-random event. The assumption therefore is that the weather has continually worsened over more than a decade, from 1993 to 2008. However, as Dr. Kaufman states weather events fluctuate "wildly from year to year" i.e., they are a random event. While there is no doubt that weather plays a significant role in maintaining service reliability, the weather events described by Dr. Kaufman are not so unusual that the distributors would not have anticipated such occurrences with regularity in the maintenance and operation of their systems.

Third, the data indicates that there are a number of distributors out of the more than 80 in the sample that have not experienced deterioration in reliability. These distributors are widely spread across the province and it would be highly unlikely that they would have escaped the

[35] Kaufmann, p.59.

weather experienced by the remaining distributors which they would have had to do if weather were a cause of the long term degradation.

4.4 Impact of IR

There is another potential weather-related issue. If distributors have not over the past decade been making adequate capital additions or replacements necessary to operate the network as reliably as in the past, reliability degradation would likely occur over a medium-run time frame. We would witness increasingly poorer reliability as infrastructure ages or is pushed to the edge of operating limits and therefore less able to withstand weather events. On a number of occasions, large distributors have gone on record with the Board stating that they do not have the monetary resources to replace sizeable portions of their networks. These distributors requested that they be allowed to fund capital replacement projects outside of the Board's normal IR rate setting mechanism so that infrastructure deficiencies could begin to be corrected.[36]

Ontario's large distributors have warned the Board for some time about the "aging infrastructure and the significant increases that would be required in capital spending in the next decade."[37] These LDCs have been explicit in their warnings: "*The Board must address this situation or the ability of LDCs to maintain reliable and cost effective distribution systems will be impaired*."[38] The largest LDCs in Ontario filed evidence detailing the aging infrastructure and the capital budgets necessary to sustain their networks.

For example, defective equipment was responsible for 27% of Hydro One's SAIFI for the period 2005-2008.[39] According to Hydro One, this performance could be improved by improving programs and increased funding[40]. Hydro One has indicated that it has deferred large numbers of system defects since 2005 and that while this "has not, to date, resulted in an increase to equipment caused outage levels" Hydro One is of the view that this situation cannot be sustained indefinitely.[41]

Clearly, the degradation we have seen in Ontario's composite SAIDI is consistent with such deficits in LDC capital budgets.

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[36] For example, this was discussed at length at a Technical Conference (EB-2006-0089) on a Second Generation IR mechanism on September 22, 2006.

[37] For example, Coalition of Large Distributors, "*Incentive Regulation-Business Considerations*," Presentation to OEB Technical Conference, EB-2006-0089, September 21, 2006.

[38] Ibid.

[39] EB-2009-0096, Exhibit A, Tab 4, Schedule 1, p.20, Figure 5.

[40] Ibid, Exhibit H, Tab 6, Schedule 1, p.2.

[41] Ibid, Tab 1, Schedule 21.

4.5 Laissez Fair SQR Regulation

It is clear from the data collected by the Board that some distributors are not compliant with the standards established in 2000. Despite the warnings of the Implementation Task Force, the admonitions in the Board's 2000 Decision, academic research on the potential reliability perils of IR, and the pitfalls experienced in a number of other jurisdictions, distributors have not been subject to compliance tests with the original standards.

Unfortunately, Board Staff have chosen to view the standards as voluntary and therefore unenforceable, contrary to the clear minimum standards outlined by the Board in its Decision in year 2000.[42] It is also clear that there has been a long-term degradation in the reliability of LDCs. Even the 2008 Board Staff Report's findings regarding the extent of LDCs' inability to meet various potential reliability targets failed to raise concerns about the service that many customers were receiving.

4.6 Unstable Policy Environment

The policy environment has resulted in significant increased responsibilities and new costs for the distribution sector. The Provincial Government, through its regulator the OEB and through legislative changes, has instituted several waves of sweeping regulatory changes in the past 10 years that have substantially affected the electricity distribution sector.

In order to see if management might have taken their eyes off the ball with the sweeping policy changes, let's look at other areas of performance. Have other operational aspects of distributors suffered during this period?

Let's look at some data on distributors' performance prior to restructuring. First, the distributors had produced robust productivity growth over the 1988 – 1997 period. Over the 1993 – 1997 period, average total factor productivity ("TFP") growth of about 2 percent was exhibited across a broad set of large, medium and small distributors. Second, cost increases had been moderate. Third, by 1997, the distributors exhibited a very high level of technical efficiency (93 percent); a number of these utilities were on or very near the efficiency frontier.[43] Fourth, one area that needed improvement was allocative efficiency. Due to the incentives faced by utilities in

[42] One could quibble with Board Staff's characterization of the standards. Compliance with the rate handbook is a condition of licence. Since 2001, non-compliance with licence conditions has been subject to fines. Even if a utility interpreted the standard as being adjusted based on future degraded performance, such performance should set a compulsory ceiling on outages.

[43] F. Cronin, S. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," *Annals of Public and Cooperative Economics, 78, No.4, 2007.*

Technical efficiency measures the degree to which firms are operating at an optimal output to input ratio, given the set of inputs selected by the firm. In this case, by 1997, the average Ontario MEU was only 7 percent lower than the most efficient, best practice utilities, i.e., if the average firm were to operate as efficiently as the most efficient MEUs, the average MEU would be able to raise its output only 7 percent with inputs held constant.

general, as well as some more specific to Ontario, the distributors' allocative efficiency was only about 80 percent.[44]

Now, what has happened since restructuring? First, consultants working directly for the largest distributors in the province have filed reports with the Board that indicate TFP has declined anywhere from 0.5 per cent to 1.7 per cent per annum in the years 2002 – 2007.[45] Second, as documented in my earlier paper, costs have increased despite the mergers.[46] In some cases, these cost increases wiped out a decade's worth of productivity gains accrued over the 1988 – 1997 period. Third, efficiency has declined over the past decade.

Thus, we do find confirmatory evidence that distributors have suffered operationally over this period: sector-wide distribution productivity growth under the OEB's decade long regulation has been significantly negative, unlike the positive, broad based productivity growth from 1988 to 1997. And, not surprising given the focus on O&M, allocative efficiency has declined as well.

4.7 Changes in Governance

Prior to restructuring, the non-commercialized electric distribution sector in Ontario evolved over a ninety year period into a technically efficient, highly reliable provider of power. Its institutional characteristics (e.g., many dispersed, power at cost, no debt, distribution-only utilities) reflected the incentives and constraints within which the distributors operated. One important aspect of this organizational structure was the local control over utility operations provided by municipalities and the community representatives comprising the municipally elected and appointed commissioners.

The Ontario Government in encouraging amalgamations failed to understand that scale effects were minimal, at best, and negative for a large number. Furthermore, the very strong efficiency incentives from local governance appear to have been muted as merged organizations became both larger and more distant, organizationally and geographically. More troubling, restructuring and changing governance appears to have come with reduced service quality, which prior to 2000, was among the best in North American and Europe. On average, Ontario distributors have experienced a ***significant deterioration*** in reliability from 2000 to 2008.[47] Customers are experiencing both more frequent outages and longer outages. As noted in a recent article on restructuring in the U.S. electric power sector:

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[44] Ibid. Allocative efficiency measures the degree to which firms are employing inputs in optimal combinations. Also see, Cronin, F.J., and Motluk, S., "The Road Not Taken," *Public Utilities Fortnightly*, March 2004.

[45] Julia Frayer, Presentation to Third Generation Incentive Regulation Consultation (Board docket EB-2007-0673) on behalf of Coalition of Large Distributors, London Economics International LLC, Aug. 5-7, 2008.

[46] See, Cronin, F.J., and Motluk, S., "How Effective are M&As in Distribution? Evaluating the Government's Policy of Using Mergers and Amalgamations to Drive Efficiencies into Ontario's LDCs," *Electricity Journal*, April, 2007.

[47] See, Cronin F. and S. Motluk, Ontario's Failed Experiment, *Public Utilities Fortnightly*, Part 1 July, 2009 and Part 2 August, 2009.

> *One neglected issue in these evaluations of restructuring is any possible effect on service reliability... Such effects would not be surprising, as restructuring has replaced the vertically integrated utility's "obligation to serve" with contractual arrangements and information… This altered structure and incentives indisputably can affect outcomes, as is evidenced …by studies of the quality effects of incentive regulation in electricity and other markets…*[48]

Operating under the belief that removal of hundreds of locally focused distributors would result in sizeable efficiency gains, the Ontario Government has continued its consolidation policy through tax policy: publicly-owned utilities have been given periodic exemptions from the transfer tax when selling assets to other public utilities, "a move designed to encourage consolidations among municipal electrical utilities."

While scale economies proved negligible, scope economies were quite substantial (e.g. input sharing between utilities). Another important characteristic of this evolution in local distribution is the varied boundary arrangements selected by utilities for providing outputs and procuring inputs. Such benefits from local management and organizational initiatives were not recognized or fully understood by Ontario's government and regulator during the restructuring that occurred between the 90th and 100th year of the sector's existence. While the Government ignored the potential for scope economies to achieve cost efficiencies, the regulator implemented competition policies which impeded the legacy institutional arrangements already in place without understanding their cost implications.

4.8 O&M Focused IR

Most troubling has been the incentives embedded in the Board's 2nd and 3rd Generation IR frameworks. Ter-Martirosyan finds that utilities on IR without SQR standards reduce their expenditures throughout the time period of her analysis by 37 percent. On the other hand, utilities with IR and standards and penalties increased their expenditures in every year rising by 17 percent. The former utilities were found to have had a 64 percent increase in SAIDI and a 13 percent increase in SAIFI. The latter utilities were found to have had a 26 percent decrease in SAIDI and a 23 percent decrease in SAIFI.

The 2003 Staff Report and subsequent reports (e.g., the 2006 Christensen report[49], 2007 Pacific Economics report[50] and 2008 Pacific Economics report[51]) focus on O&M-based operational efficiencies associated with technical efficiency (i.e., achieving the maximum output to input ratio) while ignoring capital (about half of total costs) and associated allocative inefficiency.

[48] Kwoka, J. "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies, Review of Industrial Organization, (2008), p.193.
[49] Christensen Associates, "Methods and Study Findings: Comparators and Cohorts Study for 2006 EDR".
[50] Pacific Economics Group, "Benchmarking the Costs of Ontario Power Distributors," April, 2007.
[51] Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario Report to the OEB, February 2008.

Consistent with the Board's focus on O&M, research on the post-PBR efficiency of the distributors finds that allocative inefficiency has increased since 1997. But, whereas the heavily capitalized networks of the 1990s had robust reliability performance, the now, more inefficient networks have degraded reliability due to non-optimal O&M expenditures. Most troubling is the fact that the OEB has now formalized its IR based substantially on O&M benchmarking without considering inter-utility differences in labour capitalization policies or reliability performance. Ignoring differing capitalization policies will distort O&M comparisons and create differences in benchmark outcomes which are figments of accounting alone. Ignoring reliability in the O&M benchmarking will incent LDCs to cut O&M even if it degrades reliability. Indeed, research over the past decade finds that O&M reductions were significantly related to reduced reliability.[52]

4.9 Technical Causes of Service Interruptions and Board's use of the Records

There is enough evidence of reliability degradation in the OEB's dataset to question the assertion in the 2008 Board Staff Report that there are no concerns with reliability levels in the Province. However, it is impossible to sort out causes for the degradation in reliability based on the reported reliability data. As indicated in the 2008 Board Staff Report and as mandated by the Board's 2000 Decision, all service reductions, regardless of cause, are used to calculate the interruptions indexes. It may be that reliability has been affected by causes beyond a distributor's control, for example, loss of supply from the transmission system.

As part of the original reliability indicator reporting requirements established in the 2000 Rate Handbook, distributors are required to record the reason for supply interruption, but are not required to report this to the Board. This requirement was continued in the 2006 *Electricity Distribution Rate Handbook* and is reproduced below. The OEB should require LDCs to provide this data retroactively to 2000 so that the historical data available to the Board can be used to determine reliability standards that truly reflect interruptions that are within the LDCs' ability to control.

[52] Cronin, F. J. and S. Motluk, "Modeling Electric Distributor Costs, Investment, and Reliability," (in process). We used Ontario LDCs data to estimate a three-equation model. We find that LDCs with higher O&M expenditures also have higher reliability (lower SAIDI, etc). Older networks, networks with lower shares of underground lines, and networks with less capital tend to have lower reliability.

Exhibit 7. Causes of Service Interruption Codes

Table 15.2 Cause of Service Interruption	
Code	Cause
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	**Loss of Supply** Customer interruptions due to problems in the bulk electricity supply system
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	**Adverse Environment** Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing (previously Code 9)
8	**Human Element** Customer interruptions due to the interface of distributor staff with the system (previously Code 7)
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects (previously Code 8)

Source: 2006 Electricity Distribution Rate Handbook.

15.3 Cause of Service Interruption

Monitoring the cause(s) of outages, in addition to monitoring the system reliability indices, provides valuable information as to the remedial work required. A distributor should therefore maintain a record of the causes of the outages, at a minimum, in accordance with the list presented in Table 15.2.

While annual reporting of this information to the Board is not mandatory, the Board will expect the distributor to produce this information should a review of its service reliability be necessary.

The following cause codes have been updated to correspond with the Canadian Electrical Association's guidelines.

Source: 2006 Electricity Distribution Rate Handbook.

4.10 Interpretation and Compliance with Reliability Standards

The Board should direct LDCs to report whether or not they are compliant with the standards articulated in the Board's 2000 Decision. The 2000 Rate Handbook and 2000 Decision directed utilities at a minimum, to maintain service quality: those utilities with data were to stay within the performance floor established by their preceding 3-year performance.[53]

In its initial PBR rate setting guidelines set out in the 2000 Rate Handbook, the OEB spelled out the reasoning behind the standards:

> *…the Board's approach to encourage the maintenance of service quality during the first generation PBR plan is to apply minimum standard guidelines for customer service indicators, and to apply a utility's historic performance as its specific service reliability standards. Where a utility has not monitored service reliability in the past, it is required to initiate monitoring and reporting of the indices. (7-2)*

Thus for SAIDI and SAIFI, "All planned and unplanned interruptions of one minute or more should be used to calculate this index. Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance." (7-6, 7-7)

With respect to service degradation and remedial action, the Board noted:

> *In the absence of historical service quality data, it is not possible to identify service degradation during the first year of the PBR plan. However, upon review of the first year's results, the Board will determine whether there is sufficient data to set thresholds to determine service degradation for years 2 and 3. When established, the Board will issue these thresholds and any utility whose performance falls below these thresholds will be required to file a remedial action plan. (7-10)*

As noted by distributors at the October 15, 2010 stakeholder conference, some distributors have chosen to interpret the guidelines in the 2000 Rate Handbook to mean that *future performance will become historical and can then be used to set lower and lower standards*. As a result, some distributors have implemented the guideline in a manner that allows for targets and standards to lower future reliability performance. This was clearly not the intention of the Board in 2000.

In its 2000 Decision on First Generation PBR, the OEB found:[54]

> *Any reduction in the quality and/or reliability of a service represents a reduction in the value of that service. **Therefore, as part of its function in regard to approving or fixing just and reasonable rates, the Board has a responsibility to oversee that service quality is preserved and improved**… the Board favours the minimum standards proposed in the draft Rate Handbook for first generation PBR. **The Board notes that these standards***

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[53] See also 2006 Electricity Distribution Rate Handbook. May 11, 2005. Chapter 15 – Service Quality Regulation, pp.140-143. *http://www.oeb.gov.on.ca/documents/edr_final_ratehandbook_110505.pdf*

[54] OEB Decision on Performance Based Regulation for Electricity Distributors, RP-1999-0034, January 18, 2000, pp.50-53.

> ***represent the minimum acceptable performance; a utility should continue to establish its operating performance at any level better than the minimum standard****, taking into consideration the needs and expectations of its customers and of cost implications.* [Emphasis Added]

Note the wording used in the 2000 Decision emphasized in bold above. There is nothing unclear about the intention of the 2000 Decision.

4.11 *Force Majeure*, Deferrals , and the Endogenization of Degradation

For reporting purposes, the OEB requires that "All planned and unplanned interruptions of one minute or more should be used to calculate" performance. For internal purposes, some LDCs have employed *force majeure* adjustments to assess their own performance. For example, Hydro One deems a *force majeure* to have occurred when 10% or more of its customers have been interrupted by an event[55]. Hydro One also used such adjustments to reliability data in the 2006 and 2008 distribution COS applications. By its nature, this definition focuses on the consequences of a system failure, rather than the cause.

With regard to *force majeure* Board Staff pointed out in the past:

> *…**force majeure** events are generally referred to as those events that are beyond the reasonable control of the firm, including natural disasters such as tornados, earthquakes, hurricanes, flood, other acts of God, acts of any Government, civil disorder, or similar incidents.*[56] [Emphasis Added]

However, this is not how Hydro One defines the term. Hydro One's definition differs, in that it defines *force majeure* based on a specified percentage of customers that are affected by the event. Asked to confirm that once the 10% criterion is met that there would be no assessment made as to the actual cause of the outage, Hydro One's witness replied:

> *That's fair. However, I don't think, in my experience, I've ever seen an event that hits our force majeure that doesn't start to look a whole lot like an act of God.*[57]

Of course, there is no logical reason why an outage affecting more than 10% of customers could not arise from a cause that is wholly or largely within the control of the utility, whether from equipment failures, vegetation management practices or substandard maintenance practices.

Hydro One indicated that the 10% *force majeure* protocol is not a standard in the electric utility industry; however, it maintained that, in the absence of an industry standard, it believes the 10% criterion to be reasonable[58]. Hydro One also mentions six US-based commissions and a few utilities as comparable organizations that use the 10% criteria[59]. It is not clear from Hydro One's

[55] EB-2009-0096, Exhibit A, Tab 15, Schedule 1, p.1.
[56] EB-2007-0681, Exhibit H, Tab 1, Schedule 43
[57] EB-2009-0096, Transcript, Volume 5, p.43, Lines 1-4
[58] EB-2009-0096, Exhibit H, Tab 1, Schedule 5, p.1.
[59] Ibid.

response, however, if these commissions and utilities define the term using the 10% criteria as it relates to the size of customer base impacted together with the nature of the event that makes it *force majeure*.

In any case, at least some US jurisdictions/LDCs do employ a second equally severe standard that must be met before *force majeure* is invoked. Possibly to capture the degree of weather intensity involved in a loss, some of these jurisdictions add a time of loss standard. Not only do 10% of customers need to be impacted by the event, but the loss must endure for at least 24 hours….10% for 30 minutes is not a qualifying event. This is a notably higher threshold that must be exceeded and would likely eliminate many of the events invoked using only the 10% criteria.

The 10% criteria leads to the anomalous result, whereby the worse the impact of the system failure for customers, the less the consequences to the distributor in terms of its reliability performance statistics. The definition relates to the outcome or level of damage regardless of cause and renders the distributor harmless (from the point of view of reliability statistics) with regard to service interruptions to over 10% of its customers. If this definition of *force majeure* does not require the company to investigate or assess the actual cause of the outage once damage is assessed at over the 10% threshold. All things being equal, a system that is older or weaker (for example, by virtue of maintenance deferrals) will suffer outages which are wider and lengthier than on a system which is more robust. As budget decreases result in deferrals, and as deferrals lengthen, the extent of *force majeure* declarations would increase, meaning that over time more and more degradation would be seen as acts of God rather than as the probable consequences of management decisions.

Hydro One’s internal use of the 10% *force majeure* criterion points to the need for the Board to determine how the causes of system interruptions that distributors are required to record ought to be considered in a qualitative assessment of reliability performance.

4.12 Adjustments and Definitions

Service quality performance is an indicator of a distributor’s output, a fundamental consideration in the determination of the reasonableness of a distributor’s proposed input i.e. costs. It is essential that criteria used in establishing metrics intended as indicators of a distributor’s service quality performance are comprehensible and transparent. Therefore, for the purpose of reporting service quality and in other filings, I recommend that the Board direct all LDCs to use a definition of *force majeure* that is consistent with the ordinary understanding of that term. In particular, if an LDC is to exclude events from its reliability statistics, it may only do so on the basis that the cause of the event has been investigated, has been determined to be an event beyond its control, that the number of customers that are affected by that event is a notable proportion of its customer base, say 10% or more, and that the event causes a loss of supply to those customers for a prolonged period of time, say 24 hours. In doing so, the Board can make effective use of the record of Service Interruption Causes that it requires distributors to maintain.

5.0 Service Quality Regulation and the Social Optimal Level of Reliability

Imprudent curtailments in OM&A have been shown to significantly lower distribution system reliability. Regulators in both North America and Europe have responded to profit-driven OM&A cuts with new regulatory initiatives. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed on the utilities mandates covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations.

Indeed, some regulators have taken this WTP information and explicitly incorporated the customer interruption values into their distribution price regulation. In one case, the regulator has specified a goal of achieving a socially optimal level of reliability by recognizing that customer interruption costs must be considered equally with a utility's capital and OM&A costs in utility planning and regulatory benchmarking.

5.1 The CEER Working Group, Quality of Supply Task Force

The CEER Electricity Working Group, Quality of Supply Task Force, Third Benchmarking Report on Quality of Electricity Supply 2005 also examined the reasons behind the need for service quality regulation[60].

The CEER task force report notes that quality may have a "long recovery time after deterioration." and that "quality of service is usually regulated over more than one regulatory period." (p 31)

> *In recent years, a growing number of countries have adopted price-cap as the form of regulation for electricity distribution, and sometimes also transmission, services. Price-cap regulation without any quality standards or incentive/penalty regimes for quality may provide unintended and misleading incentives to reduce quality levels. Incentive regulation for quality can ensure that cost cuts required by price-cap regimes are not achieved at the expense quality. The increased attention to quality incentive regulation is rooted not only in the risk of deteriorating quality deriving from the pressure to reduce costs under price-cap, but also in the increasing demand for higher quality services on the part of consumers. For these reasons, a growing number of European regulators have adopted some form of quality incentive regulation over the last few years. Moreover, quality is multidimensional and some aspects of quality have a long recovery time after deterioration. Hence, quality of service is usually regulated over more than*

[60] CEER, Third Benchmarking Report on Quality of Electricity Supply – 2005, Ref: C05-QOS-01-03, December, 2005.

> *one regulatory period to address numerous issues, including continuous monitoring of actual levels of performance.*

In Europe, many regulators have instituted system-wide performance standards with significant financial consequences for the regulated utilities. In addition, many of these regulators have structured single-customer guarantees with penalty payments for non-performance (e.g., restoration within a certain period or customer is eligible for a specific payment).

5.2 System-Wide Standards, Incentive/Penalty Schemes, and Single-Customer Guarantees

In Europe, regulators such as the CEER have encouraged the adoption of SQR which combines distribution continuity (i.e., reliability) standards with incentive/penalty schemes on revenues as well as single-customer guarantees with monetary payments for non-performance.[61] In fact, CEER has been publishing a benchmarking report on SQR among its constituent members since 2002; the 2005 report covered regulators from 19 member countries.

In September 2003 CEER published the "2nd Benchmarking Report on quality of supply." This report was presented at the 2nd World Forum on Energy Regulation (Rome, October 2003), debated in several conferences and raised, according to CEER, the interest of energy regulators, energy market operators and stakeholders. Meanwhile, with the enlargement of the EU, the number of CEER members significantly increased making a broader comparison possible within the framework of SQR benchmarking analysis.

As noted by CEER:

> *The General Assembly of CEER requested the Electricity Working Group to establish a Task Force for Quality of Supply (CEER QoS TF) and gave it the task of updating the previous data, widening the participation in the data collection and analysis, showing trends in various elements of Quality of Service, suggesting common indicators for the CEER members who are at the stage of introducing quality regulation and for those who would like to harmonize their existing practices with others. Practically all CEER members participated in the work of the CEER QoS TF to-date.*
>
> *When starting to work on the 3rd Benchmarking Report CEER QoS TF members…have extended the scope … In addition to the two topics (Continuity of Supply and Commercial Quality) which were addressed in the previous report, information was asked on the use of standards and incentives for quality regulation, especially with regard to continuity of supply.*
>
> *Colleagues from Austria, Belgium, the Czech Republic, Estonia, Finland, France, Great Britain, Greece, Hungary, Italy, Ireland, Latvia, Lithuania, Norway, Poland, Portugal, Slovenia, Spain and Sweden actively participated in the work of the Task Force and*

[61] CEER, Third Benchmarking Report on Quality of Electricity Supply – 2005, Ref: C05-QOS-01-03, December, 2005.

> *supplied valuable information on their own country's quality levels and standards, so that the analysis in this Report was based on the information obtained from these nineteen countries.*
>
> *The main chapters…focused on the…most important standards, the requirements, the indicators, the factors influencing the measured quality levels and on those schemes,…recommendable to be introduced in practice.*

According to the CEER task force, incentive regulation for quality comprises three aspects:

> ***measuring actual and perceived levels of quality –** a necessary and preliminary step, since setting continuity standards and/or incentive/penalty regimes requires robust and reliable data on the service actually provided and on customers' perception. …customer surveys, through which regulators can collect …information on quality as perceived by customers, which is extremely valuable for regulatory decision-making;*
>
> ***promoting continuity improvement**, which means giving utilities signals and incentives to evaluate their investment and management decisions not only in light of their costs but also taking into account the effects on actual quality levels. Regulators can promote continuity improvement especially by introducing incentive/penalty schemes, generally based on system- level quality standards that refer to the average quality level in a geographical area…*
>
> ***ensuring good continuity levels to consumers**, especially worst-served ones; regulators can do this through guaranteed standards that refer to the quality level experienced by each single customer connected to the network. Single-customer guaranteed standards are associated with the payment of compensations to the affected customers where the company fails to meet the standard.*

5.3 Willingness to Pay Valuations, Costs of Energy Not Delivered, and Analyzing the Full Societal Costs of Distribution for Benchmarking Performance

Regulators in Great Britain, Norway, Italy and Sweden among others have conducted various studies to ascertain customers' satisfaction with distribution performance or the value placed on reliability. These regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements. Some of these regulators have taken this WTP information and explicitly incorporated the values into their distribution price regulation.

In Great Britain, earlier data from 1999 was used to set some of the initial values for penalty payments. More recently Ofgem updates on customer reliability valuations were used to revalue the payments[62]. Exhibit 8 presents Ofgem's table of guaranteed standards with their associated payments to customers for non-performance. For example, under standard GS2, a distributor who failed to restore power within 18 hours under normal conditions would face a penalty of 50

[62] Ofgem RBA/DPCR4/GOSP 10/22/04 "Open Letter on Ofgem's Proposal to Implement Revised Standards of Performance Arrangements for Electricity Distributors"

pounds for residential customers and 100 pounds for nonresidential customers. This penalty would increase by 25 pounds for each additional 12 hours of non-service. Similarly for standard GS2A, a customer that experiences four or more interruptions each lasting 3 or more hours that occur in any single year (1 April – 31 March) , would be eligible for a payment of 50 pounds. In this way, the regulator tries to induce the distributor to factor in the customers costs and consequences from lessened reliability.

Exhibit 8: Ofgem Penalty Payments Associated with Guaranteed Distributors' Standards

Table A2.1 Guaranteed Standards of Performance

Reporting code	Service	Performance Level	Penalty Payment
GS1	Respond to failure of distributors fuse (Regulation 10)	All DNOs to respond within 3 hours on a working day (at least) 7 am to 7 pm, and within 4 hours on other days between (at least) 9 am to 5 pm , otherwise a payment must be made	£20 for domestic and non-domestic customers
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £25 for each further 12 hours
GS2A*	Supply restoration: multiple interruptions (Regulation 9)	If four or more interruptions each lasting 3 or more hours occur in any single year (1 April – 31 March) , a payment must be made	£50 for domestic and non-domestic customers
GS3	Estimate of charges for connection (Regulation 11)	5 working days for simple work and 15 working days for significant work, otherwise a payment must be made	£40 for domestic and non-domestic customers
GS4*	Notice of planned interruption to supply (Regulation 12)	Customers must be given at least 2 days notice, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS5	Investigation of voltage complaints (Regulation 13)	Visit customer's premises within 7 working days or dispatch an explanation of the probable reason for the complaint within 5 working days, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS8	Making and keeping appointments (Regulation 17)	Companies must offer and keep a timed appointment, or offer and keep a timed appointment where requested by the customer, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS9	Payments owed under the standards (Regulation 19)	Payment to be made within 10 working days, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS11A*	Supply restoration: Category 1 severe weather conditions (Regulation 6)	Supplies must be restored within 24 hours (see table 2.2 below), otherwise a payment must be made	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS11B*	Supply restoration: Category 2 severe weather conditions (Regulation 6)	Supplies must be restored within 48 hours, otherwise a payment must be made	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS11C*	Supply restoration: Category 3 severe weather conditions (Regulation 6)	Supplies must be restored within the period calculated using the following formula: $48 \times \left(\frac{\text{total number of customers interrupted}}{\text{category 3 threshold number of customers}} \right)^2$	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £25 for each further 12 hours

* Customers need to claim under these standards, for the remaining standards payments are automatic

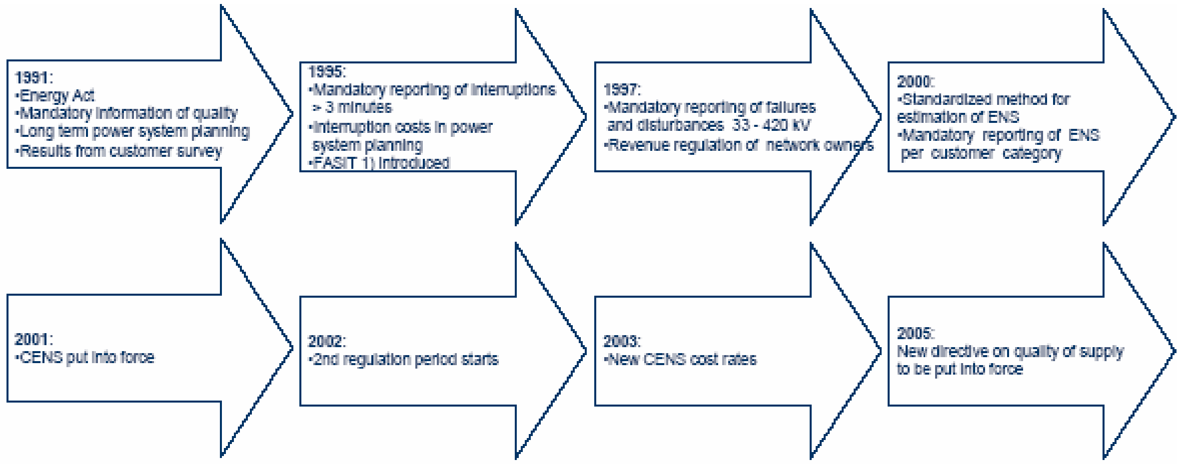
Source: Ofgem website.

Norwegian Water Resources and Energy Directorate ("NVE") recent developments with its supply quality benchmarking are discussed in "Quality of Supply Regulation – Status and Trends," by Kjell Sand, Knut Samdal, and Helge Seljeseth, researchers at SINTEF Energy Research. The authors note:

> *Recent deregulation of electricity markets around the world and subjection of electricity networks to economic Performance-Based- Regulation regimes pose a challenge to assure efficient provision of quality of supply by the regulated network monopolies. Absence of explicit regulatory framework for assuring quality of supply creates perverse incentives for the regulated network monopolies to reduce quality to meet the budgetary constraints implicit in the performance based regulatory regimes. This can over time lead to declined quality of supply.*
>
> *To counteract such consequences, the network companies are being increasingly subjected to regulatory regimes that explicitly take into account the quality of supply to the consumers. One example is the Norwegian regulation scheme CENS (Quality adjusted revenue caps), where the network companies' revenue caps are adjusted in accordance with the customers' interruption costs… (Sand, et al, p 1)*

Introduction of regulation of quality of supply in its present form in Norway has been introduced through step-wise evolution, rather than a crash-test revolution. This is illustrated in Exhibit 9 (Sand, et al, p 5).

Exhibit 9: Development of Quality of Supply Regulation in Norway



Sand, et al, Quality of Supply Regulation – Status and Trends

Sand, et al, note:

> *The CENS-arrangement [1] (Quality adjusted revenue caps by means of Energy Not Supplied) regulates only long interruptions (> 3 min). The regulator, the Norwegian Water Resources and Energy Directorate (NVE), gave the following evaluation of the CENS-arrangement at the 2003 CIRED – conference in Barcelona, May 2003:*
>
> - *"The CENS arrangement has a positive effect on the network companies' behavior and attitude related to the customers' interruption costs.*
> - *There is a need for additional regulation dealing with other quality parameters than long interruptions.*
> - *Future development to extend the CENS arrangement is possible."*
>
> *The experience with the arrangement so far, have mostly been positive, taking into account the clear limitations of the arrangement; namely to impose economical incentives for long interruptions. However, new research has proven that long interruptions only count for approx. half of the customers total costs related to interruptions and voltage dips… (Sand, et al, p.5)*

The authors present NVE's estimates of CENS by source (Exhibit 10 below).

Exhibit 10: Norway Customers' Costs Associated with Interruptions and Voltage Dips

Table 1: Customers' costs associated with interruptions and voltage dips – total for Norway

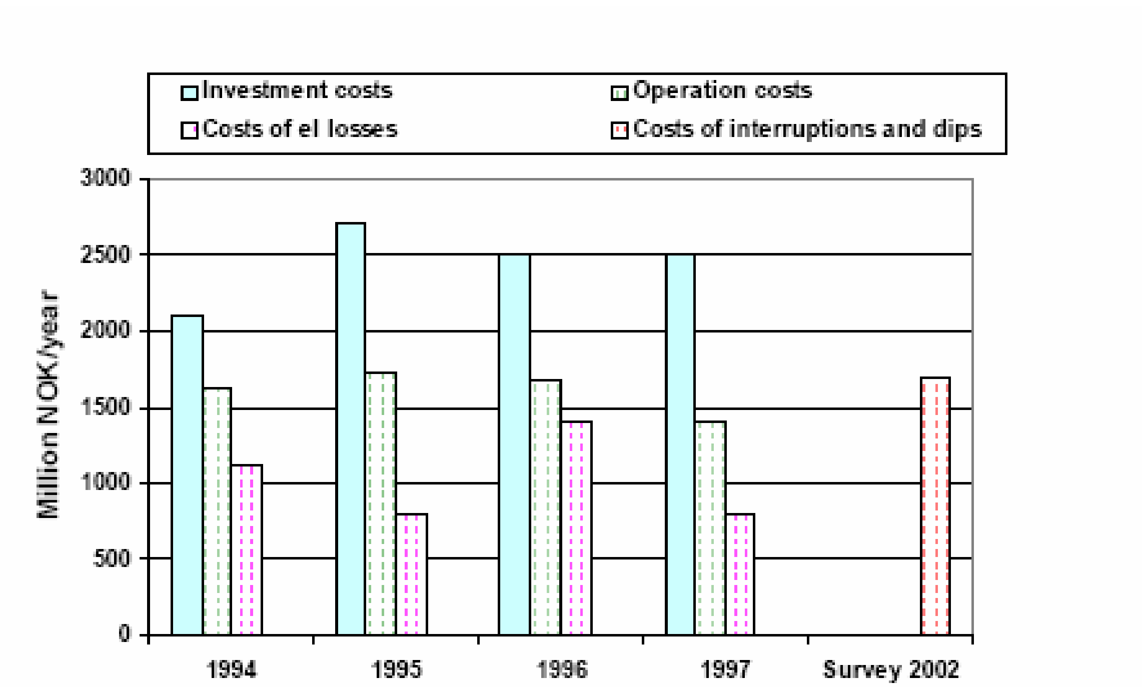
Long interruptions (> 3 min)	850 MNOK/year
Short interruptions (≤ 3 min)	600 MNOK/year
Voltage dips	170-330 MNOK/year
Total	**1 600- 1 800 MNOK[2]/year**

Sand, et al, Quality of Supply Regulation – Status and Trends

Sand, et al, also present NVE CENS estimates relative to capital investment, OM&A costs, and line loses. CENS is larger than OM&A costs as well as power loses and represent about 60 percent – 75 percent of investment costs per year (Exhibit 11).

> *These figures are compared to the network companies' internal costs related to investments, operation and maintenance and electrical losses in Figure 6.2. The customers' costs associated with interruptions and voltage dips (the "Survey 2002"-bar) actually exceed the total costs that the Norwegian network companies in sum has on operation and maintenance on a yearly basis. (Sand, et al, p.6)*

Exhibit 11: Norway Utilities Internal investment and OM&A costs and Electrical Losses



Sand, et al, Quality of Supply Regulation – Status and Trends

5.4 Yardstick Service Quality Regulation in Practice

Commenting on, the possible approaches to SQR, the 2003 Staff Report noted that "Yardstick comparisons" were an option for consideration.

> *A second method is to compare performance against that of other firms. With around 100 licensed electricity distributors currently operating in Ontario, "yardsticking" of service performance is conceptually possible. However, yardsticking appears to be little used (at least for regulatory purposes) in other jurisdictions and industries. There are a number of reasons for this. First, in most other jurisdictions, the number of regulatees is small, and so there are few firms to compare performance against. Second, these firms are, with few exceptions, local monopolies and hence operate in different areas. Geographic and environmental differences are legitimate sources of variation in performance. Finally, there are many differences in how various utilities measure their performance – even if the indicator is industry-wide.*

But, in fact, there have been a number of applications of yardstick benchmarking of service quality performance. The CEER report on service quality benchmarking notes that Italy, Great Britain, Hungary, Norway, Portugal, Spain, and Sweden have all incorporated some form of service performance yardstick benchmarking into their regulatory framework.

As the CEER report noted for Great Britain:

> *In Great Britain there is no territorial classification, but the regulator developed a methodology for benchmarking company performance that is used also to set targets for the interruption incentive scheme. Ofgem collects physical characteristics and performance information for each MV circuit for each distribution company. These circuits are then divided into 22 circuit groups with physically similar characteristics. The groups are defined so that differences in the percentage of overhead line, circuit length and number of connected customers are minimised and that no group is dominated by a single company. Performance is compared and benchmarked within each circuit group. Ofgem then establishes an overall benchmark for each company based on its mix of circuits and compares actual performance with these benchmarks. (CEER p 8)*

As the CEER report noted for Italy, there a concern was converging the worst performing distributors toward the better performing utilities:

> *Incentive/penalty schemes have been implemented in European countries with the general objective of improving/maintaining continuity levels at a socio-economically acceptable level, in particular under price- or revenue-cap types of regulation. In one case only (Italy) has the regulator designed the mechanism specifically around a country-specific objective: the convergence of continuity levels towards unique targets (for districts having the same territorial characteristics). Prior assessment of current continuity levels can, in fact, show the need to address specific issues (Table 2.6). (CEER, p 39)*

In terms of Portugal, Spain, and Sweden, the CEER report noted:

> *In all cases surveyed, the scheme includes both penalties and rewards and, since it is designed to address system-average continuity levels, is or will be complemented by some form of protection for the worst-served consumers. In general this is done by introducing Guaranteed Standards (GS) on duration and number of long interruptions (maximum*

restoration time being the most common, see section 2.4). Sometimes this assumes the form of observation of the worst-performing areas (Sweden) or, as in Portugal and Spain, of a quality improvement plan financed through tariffs (See Additional information 2.3). (CEER, p 40)

Spain does not have an incentive/penalty regime yet, but it has set system- level continuity standards, which are not only evaluated as average levels in a given territory but aimed at identifying worst-served areas in that region. Standards are set on TIEPI, 80th percentile TIEPI, and NIEPI, and differentiated by density areas. Distribution companies experiencing difficulties in maintaining the quality required in certain areas are given the opportunity to submit, to the competent administration, a temporary action programme describing the problems that need to be corrected. Those programmes will be included in a quality improvement plan financed through the tariff. Special plans have been implemented since 2004 and the amount of expenses recovered through this mechanism has been quite large so far: for 2004 special plans received a budget of 50 million, increased to 80 million for 2005.

The CEER report also noted for Italy, Great Britain, and Hungary:

In Italy, Great Britain, and Hungary the worst performing companies have larger improvements to make: this choice enables a convergence of continuity levels for the entire country. Continuity targets are set in all cases by company. The only exception is Italy, where targets are given by territorial district. Historical performance and structural differences in network layouts must be taken into account when setting the standards, in order to set targets that are achievable for the company and valuable for consumers. Differentiating targets by density area, as in Italy, or by company, as in other countries, does just that.

For Norway, the CEER report noted the regulator's use of reliability data for all utilities to benchmark the expected performance of each individual utility after adjusting for the effects of certain structural variables:

In Norway a regression model is used to calculate "expected total interruption costs" for each company using historical data and various structural variables (energy supplied, network extension, number of transformers, wind, geographical dummies). (CEER, p 44)

5.5 Pollara's Surveys of WTP and Customer Satisfaction

I commend the Board's efforts to initiate surveys of residential and business customers' satisfaction and WTP.

Pollara's key findings include the following:

- Ontario's electricity consumers are highly tolerant, and adaptive to power outages.
- Ontario's electricity market is highly cost-conscious.
- Customer satisfaction levels, overall, are strong – with some caveats.
- Rising electricity costs are a top electricity concern among businesses and residential customers.
- Majority of business and residential consumers not willing to pay any amount to reduce number of outages.

However, Pollara's findings and conclusions need to be re-examined and re-interpreted. And, much more information on the details of their survey needs to be shared with stakeholders.

5.6 Customer Satisfaction Levels, Overall, are Strong – with Some Caveats

Focusing on Pollara's residential survey, they find somewhere between 21 and 33 percent of customers are not satisfied with service reliability. More information needs to be provided on the sample, questionnaire implementation and the interviewing training to provide context around the results.[63]

Further, Pollara provides no information on how these data translate into the Ontario distribution customer base. Accepting the findings at face value the percentage of residential customers in Ontario that are not satisfied with service reliability would translate into between about 1,000,000 to 1,600,000 customers. This clearly constitutes a significant pool of dissatisfied ratepayers. This finding is based on Pollara's decision to count as satisfied any respondent that responds with a 6 or higher on their 10 point scale. Could the respondents responding with a 6 or 7 (i.e., with a "D" or "C" grade in school) actually also be dissatisfied? Pollara responded at the stakeholder conference that their scoring represents "a middling" performance level to be included among those satisfied with their power supply.

This raises the following questions:

- Should Ontario LDCs aspire to such "middling" performance?
- What would the percentage of dissatisfied respondents be (and corresponding number) if 6s and 7s are included?

5.7 Ontario's Electricity Consumers are Highly Tolerant, and Adaptive to Power Outages

Pollara reports that 68 percent of respondents perceive that they have had an outage during the prior 12 months. Pollara reports that respondents perceive that this outage lasted 2.8 hours. Pollara also reports that among residential customers experiencing an outage, the mean number of outages is 4.8 (slightly higher for business). Among these customers 25 percent report 4 to 6 outages, 9 percent report 7 to 12 outages, and 5 report more than 12 outages. That is, 40 percent of respondents report more than 4 outages with almost 15 percent or one-sixth, reporting more than 7 and some as high as 12 or more. Forty percent of customers would equal to about 1,900,000 customers; the 5 percent experiencing more than 12 would equal to about 235,000 customers of almost a quarter of a million.

While one of Pollara's key findings is that Ontario consumers are highly adaptive to power outages, it would appear that experiencing 4.8 outages on average, or over a dozen for 1.9 million residential consumers, there is the need for consumers to be adaptive. Are customers "tolerant"? As many as 33 percent express dissatisfaction and much higher if those that ranked their satisfaction levels as 6 or 7 out of 10 are reclassified as dissatisfied.

[63] For example, prior work like Cronin (1982) provides a plethora of information on questionnaire and training. The author found statistically significant evidence of interviewer and information biases. See, F. Cronin, Valuing Nonmarket Goods through Contingent Markets. Pacific Northwest Laboratory (a US DOE National Energy Lab) for the US Environmental Protection Agency, September, 1982.

It is also important to note that the outage experience reported by respondents was worse than these customers were anticipating. Customers anticipated 3.43 outages per year; customers experienced 4.78. Customers anticipated outages would last 1.99 hours; customers experienced outages lasting 2.79 hours. That is, customers experienced 39.4 percent more outages lasting 40.2 percent longer than they expected. Clearly, network reliability is significantly worse than customer expectations.

5.8 Majority of Business and Residential Consumers not Willing to Pay Any Amount to Reduce Number of Outages… Ontario's Electricity Market is Highly Cost-Conscious

Yes, Pollara reports that 58 percent of residential customers are unwilling to pay more for better service. But, Pollara also reports that 42 percent of customers are willing to pay more. Among these latter, respondents are willing to spend $16.2 for improved reliability; among all respondents the average WTP is $4.6.

It would be surprising if respondents were not cost conscious; I am not sure this is telling the Board and stakeholders anything new. More to the point, about 2 million customers are willing to pay more for improved reliability. The mean of this increase would be about $192 per year. Should the preferences/experiences of these 42 percent or 2 million customers be ignored?

Are the expressed WTP's correlated with the customers' outage experience? Recall that about 40 percent of respondents experienced four or more outages a year.

Another question that is not addressed in Pollara's results is whether respondent gaming and the free rider problem has been addressed. Fundamental to the survey results is the lack of any reported attempt to deal with Strategic Bias or respondent gaming. Economists with experience in WTP studies are aware that some respondents will explicitly understate their actual WTP in the expectation that that response might affect decision makers. Distribution service is similar to a "common good"; upgrades can benefit many customers simultaneously and some respondents may hope for a "free ride". Some economists have labeled "0s" and other extreme bids as protest bids and conducted research accordingly.

In a study I conducted in 1982 (Cronin, 1982) I examined the presence and extent of Strategic Bias among a 2000 household survey of water quality.[64] I found that Strategic Bias is statistically significant in that analysis. The size of the bias ranged from about 10 – 25 percent.

6.0 Summary and Conclusions

The OEB instituted minimum reliability standards in its 2000 Rate Handbook: for distributors with historical data, reliability was to stay within the range of performance over the prior three-years. The Board noted that it would move to investigate the implementation of more refined standards along with non-performance financial penalties. However, the intentions laid out by

[64] F. Cronin, Valuing Nonmarket Goods through Contingent Markets. Pacific Northwest Laboratory (a US DOE National Energy Lab) for the US Environmental Protection Agency, September, 1982.

the Board in 2000 were not realized. Reliability performance by LDCs was not broached again by the OEB until 2003, and then only to produce a report on regulatory principles underlying just and reasonable rates. Not until 2008 did the Board release even a cursory examination of LDC reliability performance; furthermore, that report announced that the mandated minimum standards implemented in 2000 were not compulsory but voluntary. Since then, the Board subjected the LDCs to multiple and repeated changes in regulatory governance and rate setting. Notably, the OEB opted to implement rate adjustment mechanisms based substantially on O&M benchmarks, unadjusted for labour capitalization or reliability performance.

6.1 Reliability Degradation

Ontario's composite reliability indexes indicate that reliability has degraded significantly over the 2000 to 2008 period. A number of customers are being served by LDCs that are ***not compliant*** with their standards established in 2000. Furthermore, despite the clear dictate that the 2000 standards were to be considered minimally acceptable, some LDCs have interpreted the standards differently and implement lower standards by using the lowered post-2000 performance to establish new "historical" floors below the 2000 floors.

There is clear evidence of reliability degradation in the OEB's data to question the 2008 Board Staff Report's conclusion that there are no concerns with reliability. With the existing data, however, it is impossible to attribute cause for the degradation. As indicated in the 2008 Board Staff Report and as mandated by the Board's 2000 Rate Handbook, all service reductions, regardless of cause, are used to calculate the interruptions indexes.

While continuous significant demands on the distributors related to government policy may have contributed to the reliability degradation, implicitly, the *laissez faire* regulatory attitude displayed by the Board since 2000 has abetted the deterioration. Furthermore, the Board's growing fixation on partial cost benchmarking, as opposed to the total benchmarking advocated in 1st Generation PBR, can be expected to have incented LDCs to curtail O&M expenditures so as to improve their benchmarking score. Yet, the Board itself in 2003 reminded stakeholders that its legislative mandate requires the OEB "*... To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.*"

Some distributors have also noted problems associated with capital funding. These distributors maintained that capital budgets were insufficient to meet their network investment requirements. Indeed, a number of Ontario's large distributors have warned the Board for some time about the "aging infrastructure and the significant increases that would be required in capital spending in the next decade."[65] These distributors have been explicit in their warnings.

[65] For example, Coalition of Large Distributors, "*Incentive Regulation-Business Considerations*," Presentation to Ontario Energy Board Technical Conference, EB-2006-0089, September 21, 2006.

6.2 Addressing Critical Issues in Service Quality Regulation

In 2008, OEB Staff identified information needs in three areas as critical for implementing SQR: these included gaps in understanding compliance costs, service standards, and WTP. Previous research and analyses can provide valuable insight to Board Staff, the Board, and other stakeholders on all of these issues.

First, extensive prior work has explored the WTP for service reliability also called Value of Service ("VOS"). This research has been done in both the US and in Europe. These existing WTP studies together with an improved study by the OEB can be used to shed important light on the value that customers place on reliability and on the validity of potential research undertaken by the Board. Second, preliminary research on distributors' costs, reliability, and investment indicates that the Ontario LDC data yields meaningful results on these critical issues. Such research would help address the issue of potential compliance costs. Third, despite Board Staff's statement in the 2008 Board Staff Report, that the Board has "no objective measure of the level of reliability," regulators worldwide have implemented "appropriate" reliability standards, many of these with single customer guarantees and system-wide incentives. Some jurisdictions have chosen the socially optimal level of reliability. Many of these regulatory paradigms are based on extensive customer research on WTP and VOS.

6.3 Recommendations on Service Reliability

Reliability may have been affected by causes beyond an individual LDC's ability to control; for example, loss of supply from the transmission system. Indeed, the Implementation Task Force argued that LDCs should be held accountable for the failures under their control. (p.36)

> *One other factor that needs to be considered when calculating the indices is the effect of external causes. These causes include outages and interruptions on the transmission system, and on feeders used jointly with another utility... the reliability indices reported by a utility be adjusted so that they truly represent situations under its control.*

Therefore, as part of the original reliability indicator reporting requirements established in the 2000 Rate Handbook, LDCs are required to record the reason for supply interruption, but not required to report this to the Board. This requirement was continued in the 2006 Rate Handbook.

The OEB should require LDCs to provide this data retroactively to 2000 so that the historical data available to the Board can be used to determine how much of the degradation is outside the network and how much reflect interruptions that are within the LDCs' ability to control.

Both operational as well as regulatory governance remedies then need to be implemented and examined to see if they bring subsequent performance within mandated limits.

My recommendations on SQR for distributors in Ontario are as follows:

- In the short run, over the course of 3rd Generation IR, and in the absence of a more robust incentive regime, Ontario distributors' should face financial penalties for non-compliance with mandated minimum reliability standards.
- In the medium run, with the start of 4th Generation IR, the Board should adopt SQR which combine reliability standards with penalty schemes as well as single-customer guarantees with monetary payments for non-performance. The latter guarantees/payments should be based on some robust measure of customer interruption costs.
- In the long run, over the course of 4th Generation, my preference is to develop an incentive approach that internalizes the cost of supply interruptions; i.e., within which LDCs recognize O&M, capital, and customer interruption costs. The Board should move toward the implementation of a "socially optimal" level of reliability; not too little, not too much. Such regimes have been successfully implemented by a number of regulators. These efforts have been under way for years and are well documented (see for example CEER).

The timeline of my proposal is generally consistent with the Norwegian experience and should be doable in Ontario (see Exhibit 9). After all, the Board itself stated in 2000 that it would be in a position "to set industry service quality performance standards. Once these standards have been established, PBR incentive mechanisms with economic consequences will be introduced around the service quality indicators (2000 Handbook, p.7-10). The Board has been consistent since that decision that reliability is a critical component of the LDCs' output bundle. Now in 2010, the Board should move to address the question: what is the right level of reliability for the ratepayers of Ontario.