DISTRIBUTION SYSTEM CODE TASK FORCE

CHAPTER 4

SUMMARIES OF RECOMMENDATIONS: SYSTEM OPERATION, MAINTENANCE, UPGRADES AND REPLACEMENTS

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4.1 DISTRIBUTION SYSTEM INSPECTION REQUIREMENTS

[FINALIZED: DECEMBER 20, 1999]

Issue Statement

Common operations and maintenance (O&M) standards, which detail a utility's obligation for distribution lines inspection, maintenance and replacement, must be embedded in the code. These standards will serve to ensure consistency in approach by utilities across the province and ensure that consumers, wherever they reside or operate their business in Ontario, know the standards to which utilities must conform. The issue is:

What form should the O&M standards take in the DSC?

Options

1. **Prescriptive Approach - Define Standards:** The DSC defines what, when, and how work is to be done and defines how this work is to be reported. Specifically, the DSC prescribes a complete and detailed set of distribution system inspection, maintenance and replacement standards. The standards detail the routines, procedures, schedules and reliability standards and include work methodology, technology to be used, and frequency. The standards also detail a reporting framework that each distributor must adopt. The option provides random audit reviews by both the regulator, and/or a party designated by the OEB.

2. **Modified Prescriptive - Define Inspection and Reporting:** The DSC defines what and when inspections are to be carried out, but does not define how these inspections are to be done, nor what follow-up needs to be undertaken. This approach carries with it implicit assumption that utilities will act upon any problems that are discovered through the inspection process. The action either will take place when the inspection is being conducted, or will be scheduled at a time following the inspection, as determined by the severity of the problem and the impact of non-remedy. Action taken and the timing of that action will be left to the distributor in accordance with best utility practices and with consideration to impact, cost and severity. The DSC also includes a reporting framework, with activity reports. These reports will be submitted annually on an aggregate basis, but will be recorded on a disaggregated basis (likely by circuit) and will be available to the OEB upon request. The option provides for random audit reviews by both the regulator, or a party designated by the OEB.

3. **Minimalist:** The DSC adopts a minimalist approach such that each distributor decides the maintenance, replacement or inspection routines, procedures and schedules it should

practice. There are no specified reporting requirements, although the OEB reserves the right to request detail of a distributor's practices, based on customer complaints that are received.

Background Information

Ontario Background

There has never been a common set of reliability or O&M standards for all distributors in Ontario. Distributors currently have a wide-variety of detailed O&M practices, O&M work methods and follow-up procedures. These activities are adopted according to the needs of the individual distributors' circumstances including: the system technology, vintage and configuration; topography; customer density; customer mix and customer demands for reliability and power quality; and environmental conditions unique to the distributor's physical location in Ontario. At the same time, O&M practices have some common features driven by the desire to deliver a cost-effective distribution system, as determined through the use of generally-accepted engineering design, construction and maintenance standards.

Other Jurisdictions

The DSC O&M subgroup completed an extensive review of the regulatory frameworks that exist in other jurisdictions, including those in the United States of America (e.g. California, New York and Pennsylvania State), Australia, Argentina and New Zealand.

This material was examined to evaluate the approach chosen in other jurisdictions, the rationale for the chosen approach and the effectiveness of each, in the hope that this would help to determine which option should be chosen in Ontario.

(i) Evidence gained from the Research

The following conclusions were drawn from the research on other jurisdictions:

- There were no jurisdictions where the regulatory approach included specific maintenance practices (i.e. work methods).
- In all cases, the information provided by Utilities was available for public scrutiny.
- With respect to assessing quality of service, and reporting:
  - Most jurisdictions use a system of reporting reliability measures as a proxy for assessing the efficacy of maintenance activities.
  - Other jurisdictions use a system that defines and reports the results of specified inspection practices.

   - One jurisdiction uses a system of power quality and reliability contracts between distribution companies and their customers.
   - Some distribution companies provide for bill rebates in their general customer agreement to compensate for poor reliability or customer service.[1]

- Most jurisdictions included regulatory provisions that recognized the following:
   - The need to ensure that distributors maintain their distribution system, in a way that did not discriminate between customers or classes.
   - Maintenance standards should not trade off lower rates today for lower reliability in the future.
   - The public should be able to understand the reliability standards the regulator has implemented in the code.
   - The approach embedded in the regulations should provide a safe environment for both workers and the public.

The task force felt that similar objectives should underlie the regulatory provisions in Ontario.

(ii) The California Model

Though features of each jurisdiction's regulatory schemes had features that were attractive, the subcommittee felt that the approach adopted in California was most applicable. The group agreed that there were many benefits of adopting and modifying this approach including:

- The California system had been developed following extensive consultation of a broad stakeholder group (including consumer, employee, regulatory and distributor representatives). It could be argued, therefore, that it considered a broad spectrum of interests.

- The standards adopted in California were based upon third party “best of industry” standards (based upon a study conducted by an engineering consulting firm, Black and Veatch). At the same time, the approach recognized that these industry standards needed, in some cases, to be modified to accommodate different topography, demography/density and perhaps weather conditions. It was believed that independent guidelines are preferable since they should reflect generally accepted engineering standards, are not formed with overriding consideration of non-economic/non-engineering considerations and are therefore difficult to refute.

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[1] Telephone conversations (&/27/99) with Nick Winter and Alasdair Turner, PHB Asia Pacific LTD, Auckland NZ (64-9-309-3766).

- The California approach was developed within the context of the California PBR framework. This PBR regime specified reliability standards to which distributors had to adhere. This is similar to the Ontario framework.

- While the California Public Utilities Commission (the "CPUC") recognized that it did not want to micro-manage the activities of the distributors, it nonetheless had a broader responsibility to ensure that the reliability, integrity and safety of the system were not compromised over time under a PBR regime. This approach was seen to provide another safeguard against this possibility. Again, this is similar to the Ontario framework.

There also are, obviously, a number of drawbacks to adopting this system, including the fact that while there are a small number of distributors in California, there are some 250 in Ontario. This may represent a relatively large regulatory burden for the OEB. This led the group to consider modifications in the approach to account for this unique situation.

* * *

Based on the research above and discussions, the pros and cons for each option were evaluated.

Option 1. Prescriptive Approach - Define Standards

The DSC defines what, when, and how work is to be done and defines how this work is to be reported.

Pros	Cons
A standard set of information on work methods and reporting on O&M activities. Does provide the regulator with a standard reporting regime including reliability data.	• Most costly to implement. Expenditure to develop the system and a relatively high level of expense for the OEB to analyze the data. • May entail significant cost to implement. Distributors may reflect these costs in increased rates and present as "z" factors for consideration in PBR submissions. • Would result in a very large regulatory burden on the OEB to manage and police to ensure that the utility is complying with the DSC.

Pros	Cons
This approach does provide the OEB an Ontario-based standard system with consistent elements to allow ease of analysis. (e.g. to evaluate individual distributor performance over time, compare to PBR results, assess impact of PBR overall or on an individual distributor basis, comparative studies over time and between distributors, assess reliability standards vs. customer calls or public intervention).	• The DSC might not be sufficiently flexible to allow for changes in technologies and equipment specific to the distribution utility infrastructure or for use in inspection and O&M. • May be inconsistent with the White Paper directive, as it does not support "ensuring efficiencies are achieved in the monopoly parts of the business."
Ability to compare distributors' performance vis-a-vis their rate requests and submissions.	Would discourage utilities from seeking and adopting the most cost efficient and/or effective methodologies, technologies or practices for operating their system and accomplishing reliability standards. Absence of suitable province-wide standards for maintenance work, and a lack of data to suggest what suitable standards might be.
Ability to ascertain the cause for or track system deterioration.	Regulatory approach may be a disincentive for investors evaluating options in Ontario.

Option 2. Modified Prescriptive - Defines Inspection and Reporting

The DSC defines what and when inspections are to be carried out, but does not define how these inspections are to be done, nor what follow-up needs to be undertaken. The DSC also includes a reporting framework, with activity reports. These reports will be submitted annually on an aggregate basis, but will be recorded on a disaggregated basis (likely by circuit) and will be available to the OEB upon request

Pros	Cons
A standard set of information for reporting on O&M activities, including follow-up activities. Does provide the regulator with a standard reporting regime to compare to PBR reliability data.	May be costly to implement the new inspection standards and the reporting requirements.
• This approach does provide the OEB an Ontario based standard system with consistent elements to allow ease of analysis (e.g. to evaluate individual distributor	Regulatory burden is increased compared to the minimalist approach but not as onerous as the prescriptive approach.

Pros	Cons
performance over time, compare to PBR results, assess impact of PBR overall or on an individual distributor basis, comparative studies over time and between distributors, assess reliability standards vs. customer calls or public intervention). • Ability to compare distributors' performance vis-a-vis their rate requests and submissions. • Ability to ascertain the cause for or track system deterioration.	
Consistent with the direction of other Summary of Recommendations coming out of the DSC groups to date. Provides for flexibility of approach to recognize unique characteristics of different distributors within the context of having to comply with the overarching minimum inspection intervals.	Increased regulatory burden on the distributor.
Standardized template reporting is consistent with other elements of the DSC (e.g. the required template form for the Conditions of Service). It facilitates reporting and comparison. Standardized reporting timetables, to coincide with the PBR framework provides for some streamlining of administrative processes. It also allows for a more comprehensive review of distributor activity and performance in the context of their rate application.	
The system provides the regulator with a tracking mechanism to monitor: • Individual distributor performance relative to its plan; • Individual distributor performance relative to other similarly sized distributors; • Individual distributor performance over time; and • Overall distributors performance over time in light of the PBR framework.	LDC's that conduct more frequent inspections than the "maximum intervals" may face inappropriate PBR comparisons and pressure to reduce these cycles potentially impacting safety, reliability, etc.
Specification of inspection standards and a reporting framework, with annual reviews, provides an additional safeguard to protect the	Specifying inspection standards may lead to reduced distributor efforts from current standards with potential impacts on

Pros	Cons
interests of consumers with respect to reliability and quality of electricity services, beyond the safeguards provided for in the PBR reliability standards. Inspection standards are relevant irrespective of distributor ownership.	safety, reliability or environmental performance. The inspection cycles chosen may be too lenient or they may be too onerous. Without consistent historical evidence as to successful inspection practices, the 'correct' inspection interval is impossible to predict. The recommended cycles in Appendix 1 therefore may have to be re-evaluated in the short term should they be demonstrated to be inadequate.

Option 3. Minimalist

The DSC adopts a minimalist approach such that each distributor decides the maintenance, replacement or inspection routines, procedures and schedules it should practice. There are no specified reporting requirements, although the OEB reserves the right to request detail of a utility's practices, based on customer complaints that have been received.

Pros	Cons
Allows the most freedom for the Distributor to define what when and how work is to be done and how it is reported (if at all). Approach does not cause distributors to change as a result of the introduction of the new OEB regulatory regime. Does not require the distributor to create a detailed work method system to comply. This is the least cost option to implement as distributors would either continue current practice, or potentially reduce current practices	Could lead to a reduction in service and reliability given distributors' incentive under the PBR regime to reduce O&M spending to improve financial results. PBR reporting may not highlight service quality deterioration for several terms.
Less regulatory burden on both OEB and the distributor. freeing time for other operational and regulatory issues. The OEB does not "micro-manage" the activities of the distributors or become the "enforcer" of provincial standards.	Does not provide the regulator with a standard reporting regime including reliability data.

Pros	Cons
Would avoid potential for PBR comparison of "unlike" distributors.	• This approach does not provide the OEB an Ontario based standard system with consistent elements to allow ease of analysis. (e.g. to evaluate individual distributor performance over time, compare to PBR results, assess impact of PBR overall or on an individual distributor basis, comparative studies over time and between distributors, assess reliability standards vs. customer calls or public intervention). • Difficult to compare distributors' performance vis-a-vis rate requests and submissions. • May be difficult to ascertain the cause for or track system deterioration.
	Does not require the distributors to document practices and actual performance in a manner easily understood by independent third parties or the regulator

<u>Implementation Issues</u>

As is the case with other issues related to setting uniform standards, past practices and local conditions must be taken into account. The challenge of deciding between the benefits of moving to a system that generates uniformity across all provincial utilities versus the costs of moving to an uniform system given the diversity of conditions and capabilities is evident here, as in other elements of the DSC. Recognizing that individual differences exist, the inspection standards were modified to allow for increased frequency of inspection, since it was felt that the uniform approach could be justified to ensure the integrity of the overall distribution system.

Reliability standards, driven from the adopted inspection standards, may not be exactly equal in all locations in Ontario but a standard set of information should be available from all distributors. This reduces regulatory complexity and allows customers to compare the quality of inspection approach across Ontario jurisdictions.

Reporting requirements may be onerous for both the OEB and distributors, and distributors should not be required to submit data that is not examined by the OEB. Data should be reported electronically on an aggregate basis, annually. Data should be collected over time, during the course of inspections, on a disaggregated basis (i.e. circuits) and recorded in a fashion such that it is available on a timely basis, on request by the OEB or an OEB-appointed body.

Summary of Discussion

The DSC deliberated on what operation, maintenance, inspection and replacement standards (O&M Standards) should be included as mandatory in the Code in order to achieve one of the main purposes of the Bill 35 legislation which was to “protect the interests of consumers with respect to prices and the reliability and quality of electricity service.” O&M standards included a reporting framework to which all distributors must comply.

The task force, in preparing a recommendation for the Ontario Energy Board (OEB), tried to consider the following:

- The desire to ensure distribution system reliability and quality of electricity service, both now and in the future, through the definition of O&M standards. The task force felt that this was especially important during the time when the electricity system was being deregulated and new ownership of the system was a distinct possibility;

- The DSC should be complementary to support the objectives of the PBR regime. The Performance Based Regulation ("PBR") framework did establish reliability and customer service indices on which distributors are required to report annually. The task force considered what supplemental O&M standards might be defined to enhance the service quality, thereby providing enhanced public protection.

- Recognizing the efficiency incentives inherent in a PBR regime and the distinct possibility of new private ownership in Ontario’s electric distribution systems, the O&M standards should be designed so as to prevent the degradation of the system and the consequent deterioration in the future reliability of the distribution system which could arise through deferring inspection, maintenance and replacement as utilities strive to reduce current expenditures.

- The desire to protect the interests of consumers in Ontario by considering what consumer protection measures might be available (e.g. customer complaint forums and processes, public intervention) in the situation where reliability deteriorated.

- An utility’s obligations for distribution line inspection standards should be clearly stated, should be common to all utilities and should be available to the public in a manner that is readily understood and subject to public scrutiny and input.

- Current operating practices, good utility management practices, and the cost of introduction of the new O&M standards.

Discussion addressed the particulars of the SOR, described below.

The Length of Inspection Intervals

The group recognized that the inspection intervals identified in Appendix 1 would be subject to criticism from several stakeholders and several perspectives. Some stakeholders would argue that the intervals are too lenient; others would argue that they are too stringent.

Some distributors argued that their current O&M practices are sufficient, and the frequency of action is less (i.e. the intervals are longer than the intervals identified in Appendix 1). Some distributors felt that it might be difficult to alter work programs and practices and that it would prove onerous to specify inspection intervals which were not synchronized with their defined maintenance intervals, thus potentially requiring more than one visit to the same equipment within a short interval. Some felt that it was not practical to specify inspection cycles generally since in certain cases, specific equipment may have been subject to more detailed inspection or could be newer and as such did not warrant such frequent inspections. It was for all of these reasons that the group decided to introduce the possibility of a distributor justifying ‘exceptions’ to these inspection cycles, given demonstrated performance (with criterion as detailed in the Summary of Recommendation).

The group wanted to construct the inspection regime so as to drive people towards the desired outcome, and protect system integrity. For those distributors that had already achieved exemplary reliability performance, the regime should be designed so as to encourage them to maintain their current programs. Even though their maintenance and inspection programs may not exactly match what is recommended in Appendix 1, it was not necessarily desirable to encourage them to revise their programs ‘just’ so as to comply.

The question of how many of the 250 distributors could be eligible for alternative inspection cycles was discussed. The group agreed that they did not want the inspection regime to itself be the ‘exception’ rather than the rule.

The Board will not have the resources on an annual basis to review 250 submissions for exceptions to this inspection schedule that will require review and approval. If one of the requirements for exemption is presenting current and historic reliability statistics, then fewer distributors will have historic statistics. Only those with historic reliability indices will be able to present the evidence that may support an exemption.

The group also agreed that they did not want to recommend an "off ramp" since this implies that the inspection regime will not be complied with at all. The group felt instead that the Board might grant an exemption on a certain part of the regime to the extent that it was replaced by something else, which could be demonstrated to be working.

Inspection Rules within the Context of the PBR Framework

Some parties argued that the DSC could be 'light handed' in the area of inspection, operation, maintenance and construction standards, given that the PBR regime is meant to be one of 'light handed regulation', leaving management decisions in the hands of the shareholder. Distributors are meant to develop their own standards of performance. The PBR framework also includes reliability performance indices, and some wondered why additional rules needed to be put into place. However, other parties felt that the requirement for distributors to submit reliability statistics under the PBR rules was insufficient since the PBR is currently silent on what-if any-consequences distributors may be subject to for either not conforming to some reliability standard or for any slippage in performance. There was also the expressed concern that the reliability statistics in the PBR are not sufficiently sophisticated nor detailed. Further, given that the reporting of reliability statistics may actually lag what is actually happening with respect to the distribution system integrity significantly, the reporting of reliability statistics may not be enough to track system deterioration.

On this last point, others felt that the PBR regime would monitor different 'classes' of distributors differently, with the classes being defined by how accurately the distributor had tracked reliability historically. Specifically, PBR will impact large distributors that have kept reliability statistics for a three-year period the most. These distributors will be required to keep within this historic range. For this first group, PBR will help since reliability is already so good that if they go outside a narrow range the reporting of PBR reliability statistics will easily allow identification of problems. There will be other distributors that have historic reliability statistics, but don't have programs, and they will likely have a larger band of performance within which they will have to maintain their reliability.

For the group with a larger reliability performance range, there is likely to be greater latitude, so it will take longer to be able to discern deterioration. There will be other distributors that have not kept historic reliability statistics, which will -under the PBR regime -have to begin to keep statistics and try to assess what they should do. For this last group, they have nothing to be compared against, so PBR will not detect deterioration for an even longer period of time. Yardstick comparators will not be available until the second generation PBR. Therefore, PBR has its limitations in driving performance across the range of distributors in Ontario.

"Back to the Basics" of the Inspection Regime

The group revisited why inspection cycles should be specified as all. If a distributor has 'good reliability' they can amend this or components of this. This does not guarantee that the poor distributors are going to be better, but at least they will have to be aware of, and have to follow the system. It appears that the correlation between inspection and maintenance and reliability is unclear. In fact, it may be the system equipment and configuration, design, standards of material and maintenance programs, automation, inspection and how they are applied and where they are applied which impacts system reliability. At the same time, this is trying to 'push ' parties into improving their practices and guard against those who are already doing it well from reducing their activities. The group agreed that the system could address the concern of public safety since safety might be compromised if the inspection was not conducted (i.e. inspection would uncover situations of unsafe facilities, e.g. snow up against a protective fence). In addition, system integrity might be compromised especially given the possibility of new ownership and a significant diminution of maintenance spending. PBR might catch this latter situation quite quickly as captured in the annual filing numbers for some distributors, while for others it would be impossible to know whether the utility had gone 'out of satisfactory reliability bounds'.

From a legal viewpoint, this may still not be considered as adequate due diligence. This addresses a regime which is designed to increase the probability of prevention of an incident (reduce the incidence) versus completely protecting the public or the utility.

For some of the smaller distributors, by requiring the inspection, it may require them to get the documentation together to put together the 'reliability picture' and provide them with the evidence to support them not doing it in the future.

In short, the purpose of the inspection is for both public safety and reliability. It is designed to highlight the obligations on distributors to adequately look after their system, and to keep the status quo if nothing else (i.e., we do not want distributors to do nothing, but rather do the same level at the very least, and hopefully -over time- improve).

A Negotiated Solution

After considerable discussion, thought and negotiation the inspection cycles identified in Appendix 1 were agreed to. The group agreed that some minimum inspection standards needed to be put into place in lieu of very prescriptive O&M or construction standards.

In consideration of all of the feedback, the group decided to deviate from the model developed in California which was developed to support much more descriptive O&M and construction standards, and which included detailed and intrusive inspection practices. Instead, the group agreed to include more broadly defined visual inspections, (e.g. defined to include thermography and other more sophisticated inspection methodologies).

The group also extended the inspection cycles to coincide with the term of the first and second generation PBR. It is expected that the PBR methodologies may be subject to considerable review at the end of the first generation PBR term and this inspection regime would likely be included in this review. It was noted that over the next six years, this inspection regime might eventually not be needed at all. Right now, there are relatively few distributors that are within the narrow band of reliability statistic. Over time, as yardstick comparators are available, and amalgamations occur, there may be a greater number of distributors within the narrow band of reliability statistics (i.e. performing at a higher level), and this inspection regime may therefore not be needed.

The group recognized that this inspection regime was a pragmatic approach to a very complex problem. The numbers which are agreed to are negotiated, and are based on very little concrete evidence of current operating practices of Ontario distributors. As such, they well may be too lenient or too onerous. Though the inspection intervals may well be open for review much sooner than the end of the first PBR term if they are proven to be unrealistic, they are still seen as being an improvement over nothing at all.

Recommendation

Option 2 is recommended - that the Distribution System Code adopt the modified prescriptive approach for O&M standards as described in Option 2, and presented in Appendix 1 and 2 to this document. In general, the standards should specify certain inspection intervals for overhead and underground distribution facilities, and establish an expectation for corrective action of those facilities in the event that problems are uncovered, depending on the severity and potential impact of the problem. Inspection intervals and definitions are included in Appendix 1. It is recommended that the inspection of facilities take place over three years in urban areas and six years in rural areas. These intervals were developed taking into account:

- The framework for PBR and the phase in of this new PBR regime.

- The different capabilities of utilities which will mean that the introduction of this system will be difficult for some, easy for some, and consistent with current practices for others.

- Overall, a three year interval seemed to be appropriate in light of the many changes which distributors are experiencing over the short term, and seemed reasonable in terms of good management practices for distributor facilities.

The intervals identified in Appendix 1 were developed in light of the impact on public safety and system reliability and in light of the number of customers that would be affected by an outage. The DSC therefore identifies longer intervals between inspections for rural areas given that fewer customers are affected by equipment failures in rural areas. The same criterion (i.e., public safety, impact of system failure) was considered when developing the intervals for enclosed and open stations.

These standards will be included in the code and are prescriptive in nature. The inspection standards can be changed over time, though they are subject to compliance until or unless changed by later decisions. These broad inspection standards should promote cost-effective provision of high quality service since they maintain the incentives for efficiencies inherent in the PBR framework, while providing an additional safeguard to ensure that the distribution system is safe and reliable for the public.

It is believed that regular patrolling is a crucial part of both protecting public safety and ensuring the continued reliability of electric supply. A set of inspection standards, which, on average, are seen to be reasonable in light of industry practice, are intended to be adopted as general inspection standards. It is believed that the introduction of defined, minimum inspection processes is an effective measure against which to assess the reasonableness of an individual utility's approach to maintenance and replacement of distribution facilities, since it is implicitly assumed that problems which are discovered through inspection will be corrected by the distributor in a timely way.

It is recognized that individual distributors will have sound reasons for departure from the maximum inspection intervals and that modified frequencies will be needed to meet unique circumstances for that utility. [See note 2 Appendix 1]. Modified plans would still be recorded in a similar manner to the proposed reporting format defined herein. The burden to request, define and defend legitimate exceptions would be placed on individual utilities.

To expand on this point, for some distributors a revised frequency of inspection might be contemplated justified by demonstrated good historic utility practice and demonstrated achievements in system reliability. These alternative inspection activities may be practices because of differences in geography, topography of lines, distribution system design, automation levels and vintage and technology of equipment.

The case to demonstrate not having to comply with the inspection schedule would have to be comprehensive and detailed, and the burden of proof would be the responsibility of the utility applying for an exception to some or all of the components of the distribution inspection requirements.

Revised inspection cycles will be allowed when justified by:

Content for Inspection and Reporting principles and process taken in general from the Commission Order Instituting Investigation into the rates, charges, service and practices of Pacific Gas and Electric Company, Public Utilities Commission of the State of California, filed February 22, 1995. The specific intervals were modified by the Task Force to better reflect the Ontario distributors experience, and to recognize the practical difficulties of introducing the system in a relatively short time frame. In addition, the more detailed and intrusive inspection standards adopted in California were not included in the Ontario proposal given that it was felt that these would either require interruption of service or were so detailed as to be considered part of the regular maintenance routines of equipment.

- Documented historical good utility maintenance and inspection practices, including a program to manage reliability;

- Alternative or additional maintenance activities that are practiced by the utility and can be demonstrated as being practiced.

- Achieved reliability performance. The utility will be required to submit both the current and historic reliability statistics over five years. These statistics must be verifiable. This will be measured by the following:

  – Once the data is available over the course of Generation 1 and 2 of the PBR regime, the reliability indices that are better than the average of distributors which are comparable in size and type. The reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous three year period, and;

  – The reliability indices over time for the individual utility that are at least as good, if not better, than the average of the indices over the previous five year period. Again, the reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous five-year period.

Reporting Guidelines

A distributor must submit annual compliance reports as part of the annual PBR submission of documents. The required Annual Report Forms are included as Appendix 2.

Each distributor will be required to submit Utility Inspection and Maintenance reports for each year using the same 12-month reporting period adopted in the PBR setting mechanism. These reports are to be submitted to the OEB and can be compared in subsequent submissions against actual performance. In the case of non-compliance with these requirements, the OEB may take further action (to be determined) and these actions may vary, depending on the severity of a failure to perform. In addition to the reporting as outlined above, distributors are to record and retain details of corrective action as per Appendix 2.

Overall, while the DSC specifically outlines an inspection and associated reporting system, it in no way releases distributors from the obligation to perform adequate maintenance. That is, the reports will describe the overall level of repair work required to maintain the system in good operating condition. Reports will be examined comparing historical trends and distributor performance compared to other distributors. This will allow the regulatory body to develop an overall picture of the results of the distributor's distribution facility maintenance program. The underlying records may be examined to see if maintenance activities are sustaining the system in a safe and reliable manner or whether increased or decreased funds, as requested in the PBR process, for maintenance are reasonable.

Distributors, by submitting these reports, represent and warrant that the patrols have been completed, as per the reported figures. The obligation to produce proof that the patrols had been performed, should the OEB demand such records, lies with the distributors.

Voter Summary

Consensus.

Dissenting Opinion

A party noted that the frequency of inspection specific to the outdoor open transformer and distribution station (i.e., 1 month) was too onerous.

APPENDIX 1
Distribution Inspection Standards

Inspection Cycles

In developing the standards for facilities inspections, the patrol inspection is defined as follows:

> **Patrol:** Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol highlights that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may also include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections would be recorded, and a summary document prepared in the LDC's annual reports as part of their PBR or licensing submissions.

The distributor should ensure that only qualified persons are involved in inspection activities in accordance with the Occupational Health and Safety Act. Since some inspections can expose inspectors to energized lines or high voltage circuits and equipment, and may include inspection and repair, a qualified person should be assigned to this work. This assumes that they are both properly trained to protect both themselves and the public, and to respond to those emergencies, which sometimes arise during inspections.

In all cases, the distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

The OEB or an OEB designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

It is expected that distributors will file both annual summary reports detailed patrol inspection activities that have taken place during the previous year as well as an outline of inspection plans ("compliance plans") for the forthcoming year.

Inspection cycles are categorized by the following major distribution facilities:

Transformers
Stations
Switching and Protective Devices
Regulators
Capacitors

Conductors and Cables
Vegetation
Poles/Supports
Civil Infrastructure

For each of these facilities, we further distinguish between overhead facilities and underground facilities and according to the facilities location and the relative population density.

- Rural means those areas less populous rural or suburban areas outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban though it would otherwise be defined as 'rural' according to this definition.

- Urban, or more populous areas are those with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

The following description provides what could be expected from a typical distribution line patrol inspection in terms of the types of defects that could be detected. Clearly, this will vary depending on the equipment specifics and locations, thus this should be viewed as a 'generic' patrol expectation. That is, this is a draft description of the normal expectation of a distribution line patrol in terms of the types of defects that can be visually detected, at least in part. Underground and overhead distribution equipment is treated separately.

Also, the categories listed are not necessarily a perfect match for those listed in the table marked as Appendix 1, since for practical reasons the categories need to be organized in a way that is reflective of the way that work is done.

Overhead construction line patrol:

Transformers and switching kiosks:
Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place
Grading changes
Access changes (Shrubs, trees, etc.)
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators

Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage

Substation- see notes to Appendix 1.

Switching/Protective Devices

Overhead
Bent, broken bushings and cutouts,
Damaged lightning arresters, control boxes, current and potential transformers

Underground
Security and structural condition of enclosure

Pad mounted
Security and structural condition of enclosure

Regulators
Condition of bushings
Tank corrosion/leaks
Damaged disconnect switches or lightning arresters

Capacitors
Condition of bushings
Tank corrosion/leaks
Damaged cutouts, disconnects or control cabinet

Conductors and Cables
Low conductor clearance
Broken/frayed conductors or tie wires
Tree conditions, exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag.
Insulation fraying on secondary especially open wire

Poles/Supports:
Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing

Grading changes, or washouts
Indications of burning

Hardware and attachments:
Loose or missing hardware
Insulators unattached from pin
Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

Equipment Installations (includes transformers)
Contamination/discoloration of bushings
Oil leaks
Rust
Ground lead attachments
Ground wires on arrestors unattached
Bird or animal nests
Vines or brush growth interference
Evidence of bushing flashover
Accessibility compromised

Vegetation and right of way:
Leaning or broken “danger” trees
Growth into line of “climbing” trees
Unapproved/unsafe occupation or secondary use

Civil Infrastructure-For example, buildings that house the equipment may need attention (cracking, fire hazards, etc). In addition, cable chambers, underground vaults and tunnels crossing the rail track or water are also included in this category. These inspections would likely be conducted in the patrol of the equipment with which they are “associated”.

Underground systems:

Riser poles should be checked as with an overhead patrol, with a visual check of cable, cable guards, terminators and arrestors. It is not possible to inspect underground cable directly, however, the system can be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

Cable:

Hard to check, but the system can be checked for exposed cable and/or grading changes that may have brought cable or wire too close to the surface.

APPENDIX 1 (continued)
Electric Utility System Inspection Cycles

(Maximum Intervals in Years)

Major or Substantial Distribution Facility	Patrol			Patrol		
	Urban			Rural		
Transformers						
Overhead	3			6		
Submersible	3			6		
Vault	3			6		
Pad Mounted	3			6		
Stations	Outdoor Open	Outdoor Enclosed	Indoor Enclosed	Outdoor Open	Outdoor Enclosed	Indoor Enclosed
Transformer Station	1 month	1	1	6 month	1	1
Distribution Station	1 month	1	1	6 month	1	1
Customer Specific Substation	1	3	3	1	3	3
Overhead	3			6		
Underground	3			6		
Pad Mounted	3			6		
Regulators	3			6		
Capacitors	3			6		
Conductors and Cables						
Overhead	3			6		
Underground	3			6		
Submarine	3			6		
Vegetation (see note below)	3			6		
Poles	3			6		
Civil Infrastructure (see note below)	3			6		

Notes

1. The above distribution system patrol cycles form part of the regulatory framework and are minimum inspection requirements for each major or substantial distribution component and related hardware.

2. The Distributor may determine that more frequent inspections may be required due to local conditions such as geographic location, climate, environmental conditions such as air pollution or highway salt spray, technologies available to perform the inspection, type and vintage of distribution technology in place, manufacturer specifications, system design, or relative importance to overall system reliability of a particular piece of equipment or portion of the Distributor's system.

   The case to demonstrate not having to comply with the inspection schedule would have to be comprehensive and detailed, and the burden of proof would be the responsibility of the utility applying for an exception to some or all of the components of the distribution inspection requirements.

   Revised inspection cycles will be allowed when justified by:

   - Documented historical good utility maintenance and inspection practices, including a program to manage reliability;

   - Alternative or additional maintenance activities that are practiced by the utility and can be demonstrated as being practiced.

   - Achieved reliability performance. The utility will be required to submit both the current and historic reliability statistics over five years. These statistics must be verifiable. This will be measured by the following:

     – Once the data is available over the course of Generation 1 and 2 of the PBR regime, the reliability indices that are better than the average of distributors which are comparable in size and type. The reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous three year period, and;

     – The reliability indices over time for the individual utility that are at least as good, if not better, than the average of the indices over the previous five year period. Again, the reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous five-year period.

3. The method by which inspection cycles are structured and the work carried out is at the discretion of the Distributor. The above table is organized according to major classification of equipment, however Distributors may choose to conduct and record the inspections on some other basis such as:

   - Circuit or feeder basis
   - Overhead & underground
   - System voltage

- Dividing its service area into geographical areas
- Other

It is intended that if the inspections are organized by one of the above approaches, all major equipment categories identified in the table and related hardware along the line or within the area will be inspected. It is intended that the utility would perform the inspection on a minimum of approximately 1/3 (urban) or 1/6 (rural) of their system in each year, such that at the end of the first term of the PBR framework, a utility would have performed an inspection of their entire system in urban areas and approximately half of rural systems If, in any one year of the PBR framework, a utility has performed the inspection on less or more than the 1/3 (urban) or 1/6 (rural) of their system, the utility would provide an explanation of this deviation in their annual submission. For clarity, the plant will be inspected on a cyclical basis, and the cyclical interval is specific to a particular region or portion of plant, and not on the system as a whole.

4. "Civil Infrastructure": Refers to facilities and structures such as tunnels, ducts suspended from or attached to bridges, underground chambers and hand holes, towers supporting distribution plant, communication towers, buildings that house substation equipment. It is intended that civil infrastructure will be inspected as part of the patrol of the distribution system or in the course of doing normal, routine utility work. It is recognized that there may be instances where it will be extremely difficult to perform a visual inspection (e.g. where access is restricted due to energized equipment in cable chambers), and therefore the civil infrastructure associated with this would be inspected in the course of doing normal utility work which would require entrance to the chamber, which would require the utility to de-energize the equipment. In other words, the equipment should not be de-energized simply to comply with this scheduled inspection routine.

5. "Patrol": Visual inspection of major distribution system components to identify problems and hazards such as leaning poles, damaged equipment enclosures, and vandalism. This will include an inspection of all related peripheral equipment, hardware, connections, all supports and attachments (e.g. cross arms, braces, guys and anchors). This would also include an assessment of vegetation encroachment on right-of-ways.

   The patrol may highlight that a problem exists or may identify conditions that warrant a more thorough or rigorous inspection or the need for specific maintenance. The specific follow up or corrective action shall be according to the best judgment of the Distributor considering best industry practices. To further clarify the nature of problems detected during the inspection, the distributor may choose to utilize diagnostic tools such as infrared thermography, ultrasonic testing or other technologies that may emerge. Several technologies are also available for wood pole testing. Distributors may choose, (as post inspection follow up or ongoing maintenance), to conduct tests of major distribution system components on a sample basis. Issues such as the age, equipment design, exposure to adverse conditions, manufacturer specifications, and relative impact on overall system reliability may influence a Distributors decisions regarding corrective action and application of these diagnostic technologies following a patrol. In all cases, the Distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol. This may entail upgrade or replacement of specific components or equipment.

   Maintenance activities and schedules are not specified in the above table and are left to the discretion of the Distributor. The Distributor is in the best position to determine, plan and carry out necessary maintenance activities, whether repair or preventative in nature, and is responsible to do so. It is not practical to attempt to establish a regulatory regime for literally hundreds of maintenance activities that range from insulator washing, cable replacement, CO_2 cleaning of switchgear, to gas-in-oil testing of station transformers, etc. The absence of more detailed inspection or maintenance criteria in the above table in no way reduces the Distributors obligation to maintain the distribution system in a safe and serviceable condition.

The OEB or an OEB designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

7. "Rural": Generally will be defined on a circuit or sub-circuit basis by each Distributor, as areas with a customer density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the Distributor may choose to treat some parts of its distribution system as urban though it is "rural" according to this definition.

   "Urban": Each Distributor will define "Urban", or more populated areas, on a circuit or sub-circuit basis, as areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

8. "Stations": The terms "substations", "distribution /municipal stations", etc. Are frequently interpreted and applied differently by various distributors. In some jurisdictions the term "substation" refers to a large 125 MVA station directly connected to the 115 or 230 kV transmission system while in other jurisdictions "substation" refers to a customer specific station that provides transformation from a distribution voltage to a utilization voltage of 600V for example.

   The impact on overall distribution system reliability of any particular station varies considerably according to the nature of the station and local system design. Specific station design features such as indoor versus outdoor may warrant different inspection cycles according to the relative exposure to unauthorized access and associated public safety concerns.

   The following definitions are provided to assist with interpretation of the above table such that the resulting inspection cycles are appropriate for the nature of the station.

   8.1 "Transformer Station" (TS): A transformation facility with the primary connected to the 115/ 230 kV or higher transmission system and the secondary operating at 50 kV or less.

   8.2 "Distribution Station" (DS): Also known as "municipal Station (MS), a transformation facility with the primary operating at a sub transmission or distribution voltage and the secondary operating at lower distribution voltage. The upstream transformation facility will typically be a Transformer Station. A Distribution Station supplies main feeders for wide area distribution.

   8.3 "Customer-Specific Substation": A transformation facility supplying a specific industrial/commercial customer. The primary operates at a distribution or sub transmission voltage and the secondary typically operates at 600V. The upstream station could be either of the stations identified in 8.1 or 8.2. Typically these facilities are on the customer's private property and include customer-owned equipment in addition to a Distributor-owned transformer.

8.4 "Outdoor Open": Typically refers to a station surrounded by a locked security fence. Within the station fence bare energized components operating at distribution voltage levels or higher are readily accessible. More frequent inspections are required for public safety considerations and to ensure integrity of the station fence.

8.5 "Outdoor Enclosed": Similar to 8.4 above however all bare live components are enclosed in locked metal enclosures. Due to reduced accessibility to energized components less frequent inspections are appropriate.

8.6 "Indoor": Typically refers to a station located within a secure building. Access by the public to bare energized components within the station is prevented by the building enclosure. Due to reduced exposure to unauthorized public access less frequent inspections are appropriate.

9. "Conductors and Cables: Underground": It is not possible to inspect underground cable directly, however, the system can be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

10. "TBD" indicates, " to be determined" by the Distribution Maintenance Sub-Committee.

11. "Vegetation": Refers to encroachment of vegetation upon distribution lines on any right-of-way; either public road allowance or private property. It is intended that vegetation will be inspected as part of the regular patrol of distribution equipment.

APPENDIX 2
Distribution Inspection Reporting

List of Appendix Tables and Purpose

Report Title	Reason for the Report
Reporting Philosophy	• Annual reports could be a component of the annual PBR reporting framework. • The purpose of this report is to describe in statistical and word format the units accomplished in the current year by the distributor. The report framework includes summary tables of information for both the overhead and underground distribution facilities.
I. Annual Inspection Summary Report	• Sample of an Annual Report Form • The purpose of the report is to highlight the annual accomplishment as compared to the cycle requirement listed in Appendix 1. • Report highlights both the accomplishment and any deficiency from the planned levels. • Reports can be compared year to year for an individual distributor and used to prepare comparisons with other distributors.
II. Patrol Deficiency Report	• Sample of an Annual record- this information would be kept on record by the distributor and available to the OEB upon request • Identifies Conditions and Corrective Action. Purpose of the record is to provide general information on the amount of equipment where corrective action is required. It further qualifies the urgency of the repair. • Record could allow the OEB to assess the overall condition of the distribution system and provides a basis for historical trend analysis. If the trend in a specific category radically changes on a year-to-year basis, the OEB could further investigate the reasons leading to the condition. Records could be compared to results reported under the reliability performance measures (PBR) to evaluate the overall condition of specific components of the system. • Records can be used to generate year to year comparisons to develop trends for individual distributors and to other distributors

APPENDIX 2 (continued)
Annual Report Forms: Distribution Inspection Reporting

I. Sample Annual Inspection Summary Report

Distributor		
Reviewed by	Name:	Position/Title:
Date:	Signature:	

DESCRIPTION Part 1 Lines		Percentage of Distribution System Scheduled for Patrol (%)	Percentage of Distribution System Actually Patrolled (%)	Reason Patrol was not Completed	Date Patrol will be Completed
Overhead Plant Transformers Switching & Protective Devices Regulators Capacitors Conductor Vegetation Poles Civil Infrastructure	Urban				
	Rural				
Underground Plant Transformers Switching & Protective Devices Regulators Capacitors Cable Civil Infrastructure	Urban				
	Rural				

Part 2 – Substations	**Number of Substations in Distribution System**	**No. of Substation Patrols Scheduled**	**No. of Scheduled Patrols not completed**	**Reason Patrols were not Completed**	**No. of Substations not Patrolled During Reporting Period**	**Date Substation Patrol Schedule will be Resumed**
Transformer Station						
Distribution Station						
Customer Specific Substation						

Notes:

1. This report provides a summary of the patrols scheduled and carried out during the year as well as the target dates for completion of patrols which were not completed as planned.

2. This format is a sample of a summary report for patrols carried out on a geographical, system characteristic (overheard or underground) basis.

3. Major equipment categories need not be reported separately however, all categories of equipment within the particular area or circuits shall be inspected.

4. Civil infrastructure is intended to be inspected as part of patrol of the distribution system or in the course of doing normal routine utility work.

5. This report is to be submitted to the OEB on an annual basis.

II. Sample Patrol Deficiency Record

Area/District ________________________ **Date** ________________________

Circuit ________________________ **Patrolled by** ________________________

Grid ________________________ **Page** ______ **of** _____

Location	**Equipment Id. No.**	**Equipment Classification**	**Repair Required/Problem**	**Corrective Action Priority**		**Assigned to or Work Order No.**	**Date Repair Completed or Scheduled**
				Grade 1	**Grade 2**		
Number of Deficiencies for the Circuit/Area							

Notes

1. The format of this record is to be determined by Distributor based on their own system data input forms. This format is a sample for inspections done on a geographical or circuit basis and indicates the information that is expected to be collected.

2. Deficiencies and corrective action for all major equipment classifications for the area or circuit would be recorded.

3. Distributors are required to retain this information and make it available to the OEB upon request.

4. Corrective Action Grade 1 is defined as a condition requiring urgent and immediate response and continued action until the condition is repaired or no longer presents a potential hazard.

5. Corrective Action Grade 2 is defined as a condition requiring timely corrective action to mitigate an existing condition which, at the time of identification, does not present an immediate hazard to the public, Distributor employees, or property.

4.2 EMERGENCY PREPAREDNESS

[FINALIZED: DECEMBER 8, 1999]

Issue

Emergency events may adversely affect a distribution system and a distributor's ability to provide services to customers. The issue is:

What are distributor obligations regarding emergency preparedness?

Options

1. **Minimalist Approach:** No Distributor emergency preparedness obligations specified in the Distribution System Code (DSC).

2. **Prescriptive Approach:** Detailed DSC requirements for Distributor emergency preparedness.

3. **Modified Prescriptive Approach:** DSC reference to IMO / Market Rules emergency preparedness requirements.

Background Information

The competitive electricity market is being established with new emergency preparedness obligations that will apply to distributors in addition to other market participants. These obligations are set out in the Electricity Act, Market Rules, and Transitional Distributor Licenses, as follows.

Electricity Act, 1998

Section 39 of the *Electricity Act, 1998* states the following:

"(1) The Minister shall require the IMO to prepare and file with the Minister such emergency plans as the Minister considers necessary.

(2) The Minster may require a market participant to prepare and file with the Minister such emergency plans as the Minister considers necessary.

(3) The IMO shall assist in coordinating the preparation of plans under subsections (1) and (2).

(4) The Minister may direct the IMO or a market participant to implement an emergency

plan field under subsection (1) or (2), with such changes as the Minister considers necessary."

Market Rules

Extensive revision to the Market Rules, Section 11 - Emergency Preparedness and System Restoration, have been developed by an Emergency Preparedness Task Force (EPTF) established by the Ministry of Energy Science & Technology and led by the IMO. This revised section of the Market Rules clearly sets out market participant obligations regarding emergency preparedness. The revised section was accepted by the IMO Technical Panel (September 1999) and the IMO Board of Directors (November,1999).

The following excerpts of the Market Rules, Section 11 - Emergency Preparedness and System Restoration are provided below to illustrate distributor emergency preparedness obligations.

11.2.3 In order to assist the IMO in fulfilling its responsibilities under section 39 of the Electricity Act, 1998, each market participant shall prepare and submit to the IMO an emergency preparedness plan and such other emergency preparedness related information as the IMO considers necessary. Each market participant shall ensure that its emergency preparedness plan complies with section 11.2.4 and is submitted to the IMO not later than 4 months following the coming into force of this Chapter....

11.2.4 Each market participant shall ensure that its emergency preparedness plan:

11.2.4.1 . . .

11.2.4.2 complies with such emergency planning criteria as may be designated by the IMO.[2]

11.2.4.3 complies with a relevant reliability standards.

11.2.4.4 is consistent with the emergency planning and preparedness procedures established by relevant government authorities.

11.2.4.5 indicates the manner in which the impact of an emergency on public health and safety will be mitigated.

11.2.4.6 indicates the manner in which the market participant will minimize the

2 .These criteria are outlined in the Ontario Electricity Emergency Plan (OEEP) identified in section 11 and developed through the EPTF.

cutting and expedite the restoration of critical loads and sensitive users during short and prolonged emergencies.

11.4.1 The IMO shall review each emergency preparedness plan . . . submitted to it and shall prepare and provide to the relevant market participant a record of review indicating the changes, if any, required to be made and the date by which the revised emergency preparedness plan must be submitted to the IMO.

11.5 The "record of review" is required to be filed with the Minister by the market participant together with copies of its emergency preparedness plan and any subsequent revised versions of the plan.

The Market Rules also deal with the subjects of annual review of the plan, independent audits or peer reviews every three years, and drills and exercises.

Transitional Distribution Licence

Article 11 of the Transitional Distribution Licence relates to this point in that it states that . . . "The Licensee shall comply with the applicable provisions of the Market Rules."

In consideration of all of the above, it appears that the subject of emergency preparedness is thoroughly addressed by the Market Rules, will be administered by the IMO, and are a condition of the Distributor Licence.

In addition, a number of emergency planning resources are available to distributors, including the MEA Guide to Utility Emergency Planning.

Definitions

<u>Market Participant</u>: (Electricity Act and Market Rules) A person who is authorized by the Market Rules to participate in the IMO-administered markets or to cause or permit electricity to be conveyed into, through or out of the IMO-controlled grid.

<u>IMO Administered Market</u>: (Electricity Act) Means the markets established by the Market Rules.

<u>IMO Controlled Grid</u> (Electricity Act) Means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operations.

Summary of Discussion

Although the Market Rules is likely to apply to most distributors, there may be some that are not wholesale market participants and therefore not obligated to the Market Rules. Task Force members confirmed it was advisable to include in the recommendation section a statement that all distributors are subject to the emergency plan portions of section 11 of the Market Rules.

The need to amend the recommendation regarding Mutual Assistance Plans was identified since a Mutual Assistance Plan with a neighboring distributor may not always be the best approach. For instance, the neighboring utility may be several hours away from remote utilities or an arrangement with a local contractor may be more practical. Escalation of distributor response to an emergency and Mutual Assistance Plans are not specifically spelled out tin the market rules however they are built into the standard against which the IMO will review distributor emergency plans. Detailed information regarding escalation of response and mutual assistance is provided in the MEA Guide to Utility Emergency Planning.

Recommendation

Given that the Market Rules include detailed and specific distributor obligations regarding emergency preparedness and will be administered by the IMO, and given that compliance with the Market Rules, where applicable, is an obligation of the Distribution Licence; option 3, the modified prescriptive approach is recommended.

The Distribution System Code should state that a distributor will develop and maintain appropriate emergency plans to comply with the Market Rules. This will include Mutual Assistance Plans with neighboring Distributors or other measures to respond to a wide-spread emergency.

Voter Summary

Unanimous.

Dissenting Opinion

None.

4.3 DISTRIBUTOR REQUIREMENTS REGARDING UNPLANNED OUTAGES

[FINALIZED: DECEMBER 8, 1999]

Issue

This summary addresses distributor obligations during unplanned distribution system outages and should be considered in conjunction with a parallel recommendation dealing with Emergency Preparedness. In the background section, possible distributor obligations have been grouped into two main areas: preparation and response. The issue is:

What are a distributor's obligations with respect to unplanned outages?

Options

1. **Minimalist Approach:** No OEB regulation of distributor unplanned outage policies.

2. **Prescriptive Approach:** Specific DSC requirements for outage management such as detailed criteria for operation of call centres, 24 hour system monitoring & control, criteria for on call personnel etc.

3. **Modified Prescriptive Approach:** General DSC criteria regarding unplanned outage policies to augment PBR criteria outlined in the Draft Electricity Distribution Rate Handbook and to identify the components of the Distributor's Emergency Plan that will support response to a "normal" (i.e. non-emergency) unplanned outage.

Background Information

Typical Distributor practice regarding unplanned outages may include the following:

Table 1
Typical Distributor Practice Regarding Unplanned Outages

Preparation	Response
Arrange for on-call personnel appropriate for service territory & system to ensure effective response in a reasonable period of time. Identify emergency services & other critical customers such as hospital, water supply, health care facilities, designated emergency shelters etc	Overall objectives are to restore supply to the greatest number of customers in the shortest possible period of time and to restore supply to emergency services and other critical customers in the shortest period of time possible.

Preparation	Response
relative to distribution circuits for possible co-ordination with other agencies. Prearrange details of mutual aid plans with other organizations to address widespread damage to the distribution system in a reasonable time frame.	Adhere at all times to established safety rules, regulations and procedures.
Establish & operate a call centre or <u>equivalent telephone service</u>.	Advise customers that contact the call centre or equivalent telephone service regarding the nature of the problem & estimated outage duration.
Develop and provide to customers information on how to be prepared for an outage and "do' and don'ts" when an outage occurs. Utilize billing inserts, newsletters, public safety awareness programs etc. to communicate the above.	Provide updates regarding restoration efforts to customers via local media. Provide customers with instructions as required ("do's & don'ts" during an outage).

<u>Implementation Issues</u>

PBR, as described in the Draft Electric Distribution Rate Handbook, does not require reporting in regards to emergency response although distributor obligations in terms of response time by qualified personnel is specified in section 5.2.6 of the handbook. (1 hour for urban areas / 2 hours for rural)

The Handbook also sets out reporting criteria for two reliability indices, SAIDI & SAIFI, plus a third (CAIDI) which is calculated from the first two. Section 5.3.4 obligates distributors to record, but not report the cause of outages; a sample table of "Cause of Service Interruptions" is provided. Section 5.4 provides for remedial action plans to be filed by distributors that fail to meet any of the service quality criteria.

While these Handbook criteria will tend to lead distributors to adopt outage management policies that achieve a response to unplanned outages in a reasonable time, additional criteria should be specified in the Distribution System Code to address other issues such as communication with customers.

It also should also be noted that the Electricity Act and the Market Rules place increased emphasis on, and include specific market participant obligations regarding the subject of emergency preparedness. (Refer to Summary of Recommendation on this subject). This will tend to enhance an organization's preparedness to respond to routine interruptions of service since components of a distributor's Emergency Plan will support response to a "normal" unplanned outage.

The rate handbook does not address a distributor's responsibilities with respect to the provision of customer information in the areas of:

- General electrical safety awareness ("call before you dig," "it's in your hands," and other public safety programs).
- Customer preparations in advance of an outage.
- "Do's & don'ts" during an outage.
- Provision of updates or responding to customer enquiries regarding the status of repairs.
- Call centre or equivalent telephone service.
- Recognition of critical or sensitive customers.

Summary of Discussion

Task force members noted that this SOR reflects the protection of consumer interests aspect of the objectives of the DSC and documents good customer service practice. It was suggested that the recommendation 1 should refer to the PBR criteria. In addition it was necessary to modify recommendation 2 so that it referred to "available information" rather than the specific nature of the outage and the expected duration. At the outset of an outage numerous phone calls are received from customers before the cause of the outage and expected repair time can be determined.

Recommendation

Option 3, the modified prescriptive approach is recommended.

To augment the Draft Electric Distribution Rate Handbook, the DSC should require distributors to adopt outage manage policies that ensure:

1. Arrangements for on-call personnel in accordance with good utility practice to ensure compliance with PBR requirements set out in the Electric Distribution Rate Handbook.

2. establishment and operation of a call centre or equivalent telephone service and make effort to advise customers of available information regarding the outage.

3. Identification of emergency services and other critical customers such as hospital, water supply, health care facilities, designated emergency shelters, etc. relative to distribution circuits for possible co-ordination with other agencies.

No reporting is recommended for this DSC obligation.

In responding to unplanned outages, distributors shall adhere to the same safety rules and regulations that apply to routine utility work. Further references include Occupational Health & Safety Act and Regulations, Summary of Recommendation on Health & Safety.

While not necessarily a maintenance and operations issue, a distributor's obligation to provide public safety awareness information and information on customer preparation and proper conduct during an outage, should be confirmed and clarified in the DSC, possibly within the broad section on "Provision of Customer Information."

Voter Summary

Unanimous.

Dissenting Opinion

None.

4.4 DISTRIBUTOR OBLIGATIONS REGARDING SYSTEM LOSSES

[FINALIZED: JANUARY 16, 2000]

Issue Statement

One of the stated purposes of the *Electricity Act, 1998* is "to promote economic efficiency in the generation, transmission, and distribution of electricity." One measure of efficiency is the level of system losses in the operation of the distribution system. The issue is:

> Should the Distribution System Code include requirements regarding system losses in the operation of the distribution system?

Options

1. **Minimalist Approach:** The Distribution System Code should not include any requirements regarding management of losses in the operation of the distribution system

2. **Prescriptive Approach:** Establish specific DSC requirements for detailed issues such as system optimization, line design, voltage conversion, loss evaluation of transformer and purchasing decisions, and management of unauthorized energy use.

3. A combination of options 1 and 2.

Background

Distributors historically have included loss evaluation among the various criteria when purchasing equipment or in system planning and design. Loss evaluation is a consideration in functions such as conductor sizing, voltage conversion, system optimization, and transformer purchasing.

Some distributors have implemented load control programs as a means to reduce their wholesale power cost, retain customer load, or defer increased system capacity. Load control also can be used to reduce the total demand on the provincial system during peak periods or near shortfalls in generation.

In recent years, system optimization software has become available that enables analysis of a distribution system to identify a system configuration that minimizes losses. Some utilities have utilized this type of analysis, and to the degree technically and economically feasible, implemented changes in system configuration to achieve efficiency in operation of the distribution system.

In general, distributors were able to assess the overall viability of any of these activities based on an economic cost benefit analysis over a specified evaluation period.

Distribution system losses can fluctuate from one year to another for reasons other than actions taken or not taken by the utility. One factor, which contributes to this variation, is that all meters, including wholesale meters, are not read at the same time. Changing economic and weather conditions can result in reduced kilowatt-hour sales by the distributor; however, losses may not necessarily decline in proportion. Proximity (or long distances) of industrial loads and supply points and any changes in points of supply can result in changes in losses that are beyond the distributor's control. Year to year variations of 10 percent are not unusual, hence the OEB should be monitoring long term trends rather than short term variations.

Implementation Issues

How will Distribution System losses be handled in the deregulated, unbundled market?

The Retail Settlement Code combines system losses with unaccounted for energy. It is understood that the Retail Settlement System will function as follows, in terms of accounting for system losses and unaccounted for energy:

1. The IMO will bill distributors on an hourly basis according to the consumption recorded on wholesale meters using the hourly spot market price.

2. The Retail Settlement System will calculate each customer's obligations on an hourly basis using the spot market price according to load profiling for those customers that do not have interval meters.

3. The five-year average of a Distribution Loss Factor (DLF), which includes system losses and unaccounted for energy, will be used to adjust the customer's metered energy consumption. The Distribution Loss Factor will be fixed for the PBR period.

4. The distributor will bill on a monthly basis according to the weighted average spot market price for the billing period and metered customer consumption with an adjustment for losses and accounted for energy based according to the Distribution Loss Factor in effect for the PBR period.

5. If a distributor can reduce system losses, the distributor can retain as "profit" any amount that is collected from customers in excess of what is paid to the IMO. Conversely, any shortfall will be borne by the distributor.

Distributors will be assessed a number of kW-based charges on a monthly basis for transmission, network connection, transformation and other related services. In addition, distributors will pay for transformer losses within the transformer station. The distributor will allocate these charges among customer classes.

In evaluating this recommended approach, and comparing it to the current situation, there appears to be both forces which would encourage distributors to seek more energy efficient equipment/technologies and manage system losses, as well as forces which would contribute to a lack of incentive to seek such efficiencies. Some of these forces are discussed below.

The above approach appears to provide an economic incentive for distributors to consider and evaluate loss management activities. However, this incentive may be less than current practice due to shorter evaluation period and "pass through" of the cost of energy and losses. This being said, there remains some incentive to manage losses since the distributor will be responsible the cost of losses for any year where system losses and unaccounted for energy exceed the five-year average Distribution Loss Factor used in the retail settlement process.

Adjustment of customer consumption by the five year average (fixed for the PBR period) of Distribution Loss Factor, combined with the anticipated three-year PBR period suggests that any gains in kilowatt-hour efficiency achieved through system optimization, purchasing of efficient transformers, or other initiatives, will appear in the 5 year average within two PBR periods or 6 years. This will tend to result in shorter evaluation periods compared to the current practice, for example, of evaluating transformer losses over a period of 25 or 30 years.

Presently it is not clear how the kW-based charges for transmission, transformation and related services will compare with the magnitude of historical wholesale demand charges. These kW-based charges will provide an economic incentive for distributors to make energy efficient choices. Whether this incentive is greater or less that the historical situation remains to be seen. Another issue to be considered is that in future, distributors will be responsible to provide (or pay for) new transformer stations or capacity when it is required. This responsibility will provide an additional incentive for distributors to manage system losses in order to defer or avoid expenditures on new transformer station capacity.

At this time it is not clear to what extent the adjustment for system losses and unaccounted for energy will appear on the end use customer's bill. In the case of the customers served by retailers, the loss adjustment will be applied on the distributor's bill to the retailer. It is unclear how much of this adjustment will be passed through to end-use customers, nor how it will be presented on their bills. If the Distribution Loss Factor adjustment is shown clearly on end-use customer bills, there could be considerable pressure brought to bear by customers upon distributors to manage losses to the degree that the loss adjustment is visible to customers and other market participants.

Also the risk of "under collecting" for losses identified earlier will tend to lead distributors in the direction of loss management.

System optimization, loss prevention and loss evaluation are business decisions that the distributor will make through cost / benefit analysis, Productivity Factor within PBR, and customer pressure (if loss adjustments appear on the customer bill) and pressure from retailers. Specific DSC requirements for detailed issues such as system optimization, line design, voltage conversion, loss evaluation of transformer and purchasing decisions, and management of unauthorized energy use would put the OEB in the position of micro-regulating distributors and reviewing engineering designs.

System Losses within the Context of PBR

The Draft Electric Distribution Rate Handbook obligates distributors to report "line losses" in its annual PBR filings to the OEB (table 6-7). The second generation PBR also is anticipated to include reporting criteria for losses thereby providing the OEB a means to monitor losses and take appropriate action if undesirable trends develop.

The Draft Electric Distribution Rate Handbook, Section 4-3 - "The Productivity Factor and Sharing," discusses use of Total Factor Productivity (TFP) to link a Distributor's profit to improvements in the physical relationship between outputs and inputs. It is presumed that a Distributor's achievements regarding reduction of system losses would be included in its Productivity Factor thereby contributing to the Distributor's ability to earn a higher Return on Equity.

Environmental Considerations in the Context of Distributor Investment

Another stated purpose of the Electricity Act is "to facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources...". A counter balance to a reduced economic incentive to manage losses may be the enhancements of corporate image realized by a distributor through management of losses and the associated reduction of emissions from fossil fuel generation sources.

It is possible that the environmental benefits associated with a particular project, in addition to the economic benefits and financial considerations, will be included in a distributor's application to the OEB when seeking approval to construct, expand, or reinforce a distribution facility. The enhancement of the distributor's case before the OEB, by including the environmental benefits and energy efficiency aspects of the project, could be an added incentive for distributors to manage losses in the distribution system.

Load Control

Control of customer loads is a tool that may assist the distributor in getting the most out of the distribution system, defer or avoid feeder upgrades, and provides an opportunity to reduce transmission and related charges to the distributor and should therefore be an option available to distributors. In addition, when one considers the situation which occurred in the Summer of 1999 where the IMO-ordered voltage reduction and numerous public requests for customer reduction of air-conditioning, the benefit of load control to the overall provincial or regional system to mitigate temporary shortfalls in generation or transmission/distribution capacity during peak periods becomes apparent. However, there seems to be less incentive for a distributor to invest in the load reduction programs since these investments will be considered part of the competitive activity, and thus not attributable to the regulated monopoly's costs.

In many cases, control of a load by the utility is accompanied by some sort of a rebate or reduced equipment rental charges to the customer. Control of customer loads by the distributor could be viewed as a means to assist an affiliate company in renting or selling more units. In addition, the retention of load derived through load control and its associated customer incentives would tend to benefit retailers, including the distributor's affiliate.

An economic incentive for the Distributor to consider and evaluate load control programs appears to exist although it appears to be less than that which currently exists. There may be a need to ensure that distributor load control is implemented solely on the economic and technical benefits to the distributor and not as a means to enhance the activities of a competitive affiliate. However, this would appear to be an Affiliate Relationship Code issue, and not an issue for the Distribution System Code.

Summary of Discussion

Task force members suggested that the recommendations be streamlined with some of the information to be moved to the background section of the SOR. It was agreed that existing and second generation PBR regimes provide the OEB with sufficient means to monitor system losses. The group agreed that the title of the SOR should be changed to reflect "System Losses" rather than "Efficiency." The task force also indicated that control of customer loads should be an option available to distributors to efficiently utilize its distribution system.

Recommendation

Option 1 is recommended.

1. There should be no DSC obligation for distributors to implement specific management programs or policies regarding system losses. The existing PBR and anticipated second generation PBR regimes include sufficient means for OEB monitoring of system losses to ensure that system losses are adequately managed.

2. Distributors should be allowed to engage in load control activities for the purposes of more efficiently utilizing its distribution system or deferring or avoiding upgrades to the distribution system.

Voter Summary

Majority.

Dissenting Opinions

Some parties expressed concern that the current configuration of the first generation of PBR and the pass through treatment of system losses as defined in the Retail Settlement Code, may not provide sufficient incentive for distributors to manage system losses. The new regulatory scheme may not provide the same economic incentives to consider losses when designing the distribution system or purchasing equipment such as transformers. It is also unclear the degree to which consumer/retailer pressure may influence distributor management of losses. The result may be a tendency for system losses to increase gradually over time.

The concerned parties suggest that the OEB should monitor system losses (in percent) reported by distributors through the PBR mechanism and initiate appropriate action in the event that a trend towards increasing system losses, above normal year to year variations, is detected over time.

4.5 UNAUTHORIZED ENERGY USE

[FINALIZED: FEBRUARY 23, 2000]

Issue Statement

Power may be diverted from a distributor's distribution system through unauthorized energy use. This unauthorized energy ultimately is collected from other customers. The issue is:

> What are a distributor's rights and obligations under the Distribution System Code (DSC) regarding unauthorized energy use?

Options

1. Prevention of unauthorized energy use is a business issue that should be left to distributors to manage in accordance with local conditions and should not be subject to direct regulation by the OEB through the DSC.

2. Unauthorized energy use should be addressed within the context of System Losses (refer to summary of recommendation on *Distributor Obligations Regarding System Losses*). No DSC criteria for unauthorized energy use except OEB monitoring of system losses and empowerment of Distributors to detect and mitigate instances of unauthorized energy use.

3. The DSC should include a specific requirement for distributors to implement and maintain loss prevention programs to manage unauthorized energy use.

Background Information

?*Unauthorized Energy Use*? is also known as ?*Power Diversion*? and in plain English means theft of power. A Canadian Electricity Association (CEA) project entitled ?*The Extent of Energy Diversion on Customer Premises for Canadian Utilities*?, in a survey of 20,000 services within six large utilities, estimated that 1.4% of the services were found to involve unauthorized energy use and in an additional 8% theft was deemed probable.

Unauthorized energy use is accomplished by a variety of methods including but not limited to:

- Tampering with meters and service entrance equipment.
- Connection of load(s) to service conductors on line side of meter.
- Connection of load to unused flat rate water heater supply conductors.

Unauthorized energy use has the potential to create serious electrical and fire hazards. Unauthorized energy use on a system wide basis can not be directly measured but is a component of overall system losses.

?How to? information on theft of power has been in circulation for years and more recently is readily accessible on the Internet.

Unauthorized energy use is sometimes not considered a serious topic by either the courts or law enforcement agencies however, some utilities have successfully prosecuted individuals that engage in power diversion. Measurement Canada has recognized theft of power as a serious issue. To this end, Inspectors have been trained in the area of detection and through inspection to be able to determine the amount of power being diverted. This determination will be derived through inspection and then mathematical calculation to arrive at an inequity.

Legislative Background:

Public Utilities Act

After November 2000, the Public Utilities Act will not be applicable to distributors, however it is useful as background information to note that it contained provisions for:

- Penalty for willful damage or injury to utility works (including meters) by any person.

- Liability of persons doing damage.

Electricity Act / OEB Act

The Electricity and OEB Acts make no reference to penalties or liabilities for persons or entities interfering with or willfully damaging distributor equipment.

A person making unauthorized connection to service conductors or tampering with meterbase wiring/connections would be in violation of Section 113 of the Electricity Act regarding compliance with the requirements of the Electrical Safety Authority (Electrical Safety Code).

<u>Implementation Issues</u>

Customer Billing / Retail Settlement

Within the Retail Settlement Code, unauthorized energy use is considered ?unaccounted for energy? and is combined with system losses.

It is understood that the Retail Settlement System will utilize a five year average Distribution Loss Factor (DLF) specified by each utility which includes system losses and unaccounted for energy, to adjust the customer?s metered energy consumption. The Distribution Loss Factor will be fixed for the PBR period.

If a distributor is able to can reduce losses or unauthorized energy use the distributor can retain any amount that is collected from customers in excess of what is paid to the IMO. Conversely, any shortfall will be borne by the distributor.

Impact of Unauthorized Energy Use on Distributors

Unauthorized energy use results in increased system losses which have the effect of:

- Reducing distributor revenue in that the percentage adjustment for losses applied to customer bills is fixed for a specified period of time (i.e. an increase in theft comes out of the distributor?s pocket until such time as the Distribution Loss Factor is increased).
- Increasing distributor costs since kilowatt-hours diverted are not metered at the retail level, but must still be paid for at the wholesale level.
- Interfering with a distributor?s ability to achieve productivity targets, thereby threatening the distributor?s rate of return to shareholders.
- Increasing distributor third party liability to the degree that unauthorized energy use involves tampering with equipment owned by the distributor.

Impact of Unauthorized Energy Use on Retailers

Unauthorized energy use represents a lost sales opportunity for retailers but does not constitute a direct loss of a wholesale product in the traditional sense. Energy for which the retailer may have contracted with a generator is consumed by the customer but not recorded by the settlement system, thereby adversely affecting the retailer?s compliance with its contractual arrangement with the generator.

Since unauthorized energy use is combined with system losses, retailers will be charged an incrementally higher system loss adjustment factor in the retail settlement process as a result of unauthorized energy use.

Impact of Unauthorized Energy Use on the Customer

The bulk of the economic burden from unauthorized energy use ultimately falls on other customers served by the distributor since all ?diverted? power ultimately is paid for by all other customers connected to the system. This aspect of the issue places responsibility on the distributor to implement appropriate policies to manage unauthorized energy use and to call in Measurement

Canada regarding billing adjustments.

Customers and the public at large may be exposed to safety hazards as a result of unauthorized energy use. Customers have a right to expect that the industry will take reasonable measures to manage diversion of power and any of its harmful effects. The Electrical Safety Authority has a role to play in the issue through enforcement of the Electrical Safety Code.

Metering as a Contestable Service

At this point in time, the final disposition of metering as a contestable service has not been determined. The party responsible for installation and maintenance of meters and meter reading should share in some responsibility to monitor the installations and check for signs of tampering during routine meter reading and maintenance functions. This expectation should apply to Meter Service Providers in general.

Summary of Discussion

During discussion of unauthorized energy use, it was concluded that the DSC should specifically empower distributors to take appropriate action to mitigate unauthorized energy use. There was some thought to identify within the conditions of supply document the steps a distributor might follow when dealing with a case of power diversion. It was concluded however, that the distributor's authority should be stated in the Code and the specific options that a distributor might implement will be a local decision and not set out in the Conditions of Service. There was some concern that dealing with this issue within the Conditions of Service would obligate the distributor to follow a rigid procedures and would leave no room for judgment on the part of the distributor regarding issues such as evaluating the probability of a successful prosecution.

Members of the group noted that with the removal of electricity from the scope of the *Public Utilities Act*, utilities (distributors) do not have recourse through the *Provincial Offences Act* as provided in section 52 of the *Public Utilities Act*.

It was recognized that Measurement Canada and the Electrical Safety Authority should be contacted by a distributor or meter service provider when unauthorized energy use is detected. These agencies have authority to deal with contravention of the federal Electricity & Gas Inspection Act & Regulations and the Ontario Electrical Safety Code respectively.

Task Force members also expressed concern regarding whether or not unauthorized energy use will be properly managed if and when retail metering becomes a contestable service.

Recommendation

Option 2 is recommended.

The DSC should include statements that specifically empower distributors to take appropriate action to mitigate unauthorized energy use and to recover from the guilty parties, all costs incurred by the distributor arising from unauthorized energy.

Loss prevention is a business issue the details of which should be left to distributors to manage in accordance with local conditions. There are a number of economic incentives, closely related to the broader subject of system losses, which will lead distributors to implement management policies to moderate unauthorized energy use. As such, it is recommended that no specific distributor obligations regarding unauthorized energy be specified in the DSC except as noted below.

1. Due to public health and safety concerns, distributors in the course of engaging in metering and meter reading activities, should be observant and take appropriate action when tampering with metering and service entrance equipment is suspected or detected.

2. Use of existing Measurement Canada investigation services, namely Measurement Canada dispute investigation, is one method that can be used in the cases where theft of power has been detected. Similarly, the Electrical Safety Authority should be notified regarding unauthorized energy use to deal with possible Ontario Electrical Safety Code violations arising from the energy diversion.

3. Since a direct measure of unauthorized energy use on a system wide basis does not exist, the OEB should monitor loss data reported for retail settlement purposes in order to detect any upward trends in overall system losses that may indicate an upward trend in unauthorized energy use and the need for further regulatory action.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.6 CUSTOMER OBLIGATIONS DURING DISTRIBUTION EMERGENCIES AND UNPLANNED OUTAGES

[FINALIZED: JANUARY 16, 2000]

Issue Statement

During emergencies and unplanned outages, customers may behave in a way that adversely affects the distribution system. The issue is:

> What are a distribution system customer's obligations during distribution emergencies and unplanned outages?

Options

1. **Minimalist Approach:** No Customer emergency preparedness obligations specified in the DSC; rely on the Electrical Safety Code.

2. **Prescriptive Approach:** Specific and detailed DSC requirements for customer actions during distribution emergencies and unplanned outages.

3. **Modified Prescriptive Approach:** Establish DSC criteria that empower the Distributor to address customer obligations during emergencies and unplanned outages within the distributor's Conditions of Service Document.

Implementation Issues

Section 39 of the *Electricity Act, 1998* and section 11 Emergency Preparedness and System Restoration of the Market Rules set out detailed criteria applicable to market participants regarding emergency preparedness. A Summary of Recommendation on Distributor Emergency Preparedness Obligations provides detail regarding the key points of these sections.

Customers that are wholesale market participants, will need to comply with the Market Rules, to the extent that they apply. Large industrial customers are likely to be covered by the existing legislative and regulatory framework.

Many commercial, institutional and residential customers have either temporary or permanently connected emergency electricity generation capability. The Ontario Electrical Safety Code includes requirements and rules for these installations. Despite the existence of the Electrical Safety Code, utility personnel continuously must be aware of, and guard against, the hazard of back-feed from customer-owned generators that are activated during a distribution system outage. Of significant concern is customer usage of portable generators without the benefit of compliance with the Electrical Safety Code.

During unplanned outages or distribution emergencies, it may be necessary for the distributor to access customer-owned distribution equipment that is normally operated by the distributor or distributor-owned equipment located on customer property. Examples would a substation serving an industrial or institutional customer or customer-owned service in rural areas. A customer's obligation to allow access should be stated in the distributor's Condition of Service.

Summary of Discussion

During discussion it was suggested that distributors should be empowered to disconnect customers in the event of a shortage of supply due to a problem on the bulk system. The possible need for a definition of emergency was noted.

Recommendation

Option 3 is recommended.

The DSC should empower the Distributor to include statements of the following nature within its Conditions of Service:

1. Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back feed on to the distributor's system.

2. Customers with permanently connected emergency generation equipment shall notify their distributor regarding the presence of such equipment.

3. To assist with distributor outage or emergency response, customers shall make provisions, suitable to the distributor, for distributor emergency access to customer owned distribution equipment normally operated by the distributor or distributor-owned equipment on customer property; customer owned substations or rural services, for example.

4. In an emergency, a distributor shall have the right to disconnect customers in response to shortage of supply, to effect repairs on the distribution system or while repairs are made to customer-owned equipment.

5. Customers should be obligated to comply with instructions from distributors during emergency situations that may have an adverse effect on public safety, for example a downed distribution conductor.

Voter Summary

Unanimous.

Dissenting Opinion

None.

4.7 HEALTH AND SAFETY

[FINALIZED: JANUARY 20, 2000]

Issue Statement

A distributor may have obligations with respect to health and safety issues associated with the distribution system. The issue is:

> What are a distributor's obligations under the DSC with respect to Health and Safety?

Options

1. The DSC should not comment on Health and Safety.

2. The DSC should prescribe distributors to develop and maintain health and safety programs that are in excess of governmental requirements.

Background Information

There are currently requirements in place governing the operation of companies with respect to health and safety. All organizations must adhere to the requirements of the Occupational Health and Safety Act (OHSA) and Regulations as put forth by the Ontario government. Embedded within the OHSA are further requirements directly related to the operation of an electrical transmission or outdoor distribution system. The work performed must follow either:

1. The Rule Book, Electric Utilities Operations published by Electric and Utility Safety Association of Ontario (EUSA)

   or

2. The Ontario Hydro Corporate Safety Rules

The Workers Safety and Insurance Board (WSIB) have instituted an audit program (Workwell Program) whose objective is to identify poor safety performers and penalize them financially to provide an incentive to develop and maintain an effective health and safety program. WSIB have these rights to fine in accordance with the WSIB Act.

Currently, most if not all distributors are members of EUSA. Many utilities have programs either complete or well into the developmental stage. As members, distributors may take advantage of all the services provided. These services cover all aspects of health and safety geared towards a distributor setting. However there is a cost associated with membership and all services are supplied at additional cost.

The nature of the industry is such that both public and worker safety is a major concern. Distributors have incorporated many of their own practices and procedures to augment the safety rules developed by EUSA or Ontario Hydro.

It is recognized that there are some circumstances in which a distributor cannot comply precisely with Ministry of Labour requirements. The distributor may have met the regulation subject to some special review by the Ministry of Labour.

Implementation Issues

Health and Safety programs do cost in terms of money and/or time. The effectiveness of the program also varies according to the commitment made by the organization. An effective program once developed does require maintenance and auditing to ensure continued improvement.

By obligating distributors to belong to an industry recognized safety organization, it will mean some distributors will incur new costs. However it is likely that costs of health and safety program will be recouped in terms of time and money savings. In a PBR environment, there is an incentive for incorporating safety programs.

By obligating distributors to require outside contractors to comply similarly with these standards, prices for contracting services may be increased or small contractors may be driven out of business.

Summary of Discussion

The group felt that due to the nature of the electric utility business, particularly the potential safety impacts on both the public and the worker more prescriptive requirements need to be in place for health and safety. The formation of the DSC is viewed as an opportunity to reinforce the importance of health and safety with those distributors that operate in accordance with an industry recognized program and to require those distributors not operating to such a standard to institute and maintain an industry recognized program. The group felt that mandatory auditing by a recognized body would insure that safety did not become a victim to cost cutting measures. The electric utility industry has such a great impact on public safety that the group felt a recognized program also would incorporate public training requirements.

Recommendation

Although the provincial government has addressed health and safety for the general population, the electric utility industry is such that best industry practices are needed. To this end Option 2 is recommended with the following details:

1. A distributor is to be a member of an industry specific recognized safety organization.

2. A distributor shall be required to implement an industry recognized health and safety program that includes training and regular conducted audits. The program also will include Public Education and Public Safety initiatives.

3. In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during an audit.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.8 POWER QUALITY

[FINALIZED: JANUARY 20, 2000]

Issue Statement

Both distributors and customers may have obligations under the Distribution System Code regarding Power Quality. The issue is:

What are the obligations of distributors and customers regarding power quality?

NOTE: This discussion involves the quality of power when the power is on, and does not address power outages.

Options

1. The OEB should not regulate power quality through the DSC. Instead, a distributor should operate and maintain the system as it sees fit.

2. The DSC should direct distributors to follow as a minimum the most recent CSA (Canadian Standards Association) C235 Standard. The distributor should strive to monitor and control where applicable harmonic related conditions once they are identified as a distributor problem.

3. The DSC should direct all distributors to be responsible for monitoring and correcting all power quality problems identified as a concern by the customer.

Background Information

There are several aspects to power quality that affect customers. Supply voltage may adversely affect customers (the voltage may be too high or may be too low). Also the presence of harmonics may seriously damage customer equipment. Power quality problems actually may be related to load growth. Voltage drops may occur because of increased load on insufficient sized conductor. Distance also may play a role.

Many power quality problems stem from the customers own facilities. Some common causes are as follows:

1. Variable speed drives – harmonics

2. Unbalanced load – low voltage problems on a phase

3. Faulted Machinery - sudden drops in voltage
 - transient in nature

Currently, a distributor is under no obligations to supply to a particular standard. Many distributors use CSA C235 as a guide for maintaining voltage levels and taking appropriate actions. Harmonics is a much newer problem (the existence of harmonics is not new, however the level at which they now exist are presenting new problems). There are no widely used standards, however there are IEC (International Electro-Technical Commission) and IEEE (Institute of Electrical and Electronics Engineers) standards that can be referred to for guidance.

Implementation Issues

Implementation issues which must be considered include the following:

- Who is responsible for investigating the problem?

- Who must pay for the investigation?

It may seem appropriate that the onus be placed on the distributor to prove their system is not at fault. This may be reasonable as the distributor has both the knowledge and equipment to perform such an analysis. Once the distributor's system is proven to be free of fault, the customer would have the responsibility of solving his or her own internal problems. If the customers' system is lacking in some regard, it may be fair that the distributor be reimbursed for its efforts in the preliminary investigation.

Summary of Discussion

Distributor Due Diligence

In general, the distributor should monitor their system to insure that the system is not creating power quality problems for the distributor's customers.

Voltage surveys may be performed on a regular basis for feeders, stations and circuits. The net effect is to insure that end use customers do not have voltages outside the CSA C235 standard ranges. When conditions are found outside the prescribed ranges, steps should be taken by the distributor to meet the targets as directed by CSA C235.

Distributors should be prepared to adjust their voltages if problems are imminent. An adjustment may be as costly as a wide scale upgrade of conductor size or as simple as the changing of tap positions on a single distribution transformer.

Customer Responsibilities

Customers should recognize when their equipment or process may present a potential power quality problem. They should take all steps necessary to prevent the problem from reflecting back in to the distribution system (IEC, IEEE standards). The distributor should have some recourse to prevent customers from ignoring a problem, which has system wide ramifications. Customers also should recognize the voltage range in which distributors operate (CSA C235) and customers should ensure that their equipment functions properly within this range. Of particular note is the fact that the CSA standard is safety based and is not necessarily a manufacturers' standard. The nature of distribution systems is such that transient voltage conditions may occur system wide or locally when a fault occurs. Customers who cannot suffer such transient conditions should install their own devices to offset this problem.

Recommendation

Option 2 is recommended –the modified prescriptive approach that imposes requirements on both the distributor and customer, but does not prescribe specific solutions.

1. A distributor shall respond to and investigate all customer power quality complaints as required in Section 23 of The Transitional Distribution License. A report will be supplied by thedistributor if necessary. If the problem lies on the customer side of the system, the distributor may seek reimbursement for the time spent investigating. The distributor must clearly state the customer's obligation to pay for such an investigation in the Conditions of Service.

2. The distributor will monitor and make changes to their system if required to observe CSA C235 and as directed by CSA C235.

3. The distributor will take appropriate actions to control harmonics found to be detrimental to customers if generated by the distributor. If the distributor is unable to correct the problem due to an adverse impact on the distribution system, then the distributor is not obligated to make corrections. A distributor should use the appropriate industry standards (such as IEC or IEEE standards) as a guideline.

4. The distributor must make a good faith effort to communicate available information on expected power quality issues to a customer who requests such information.

5. Customers must recognize their impact on the distribution system. Any customer conditions that cause problems to the distribution system should be corrected immediately. To insure that customer conditions adversely affecting the system as a whole are corrected immediately, the distributor should have the option of disconnecting customers that do not meet the distributor's requirement.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.9 ENVIRONMENT

[FINALIZED: MARCH 7, 2000]

Issue Statement

The issue is:

What are a distributor's obligations under the DSC regarding environmental issues?

Options

1. Environmental issues will not be commented on by the DSC. Existing environmental regulations alone, enforced by other government agencies, will be relied upon to mitigate the risk to the public from environmental damage caused by a distributor's operations.

2. The DSC should prescribe that distributors develop and maintain proactive environmental programs, that complement existing government requirements.

Background Information

There are currently environmental regulations administered by the MOE, which cover many aspects of a distributor's operations. In particular, regulations concerning PCBs have been well developed and are strictly enforced. Examples of other areas where existing environmental regulations would apply are oil spills, transportation of dangerous goods and disposal of hazardous waste.

Distributors are required to comply with existing regulations by law and there are various degrees of enforcement usually depending on the program in place at the distributor and the record of past offences.

Distributors have some type of program in place for complying with the laws and regulations of the province. Depending on the size of the utility and variances in operation and design these existing programs can be simple or more complex.

Implementation Issues

Effective environmental programs do incur costs to implement and maintain. Organizing and enhancing existing policies and programs will require some effort but most utilities have some type of program currently in place to comply with the regulations.

Summary of Discussion

The group felt that focus on the environment by the government has led to effective regulations that will continue to protect the public with respect to distribution system operations.

However, the group also felt that there was a need to promote a documented and proactive approach through the DSC that would not only allow compliance with law, but also would lead to a reduction of environmental effect over time.

Recommendation

In addition to complying with all applicable regulations, Option 2 is recommended with the following details:

A distributor *should* have a corporate policy covering environmental stewardship in all the utilities' operations. A documented program, supporting procedures and appropriate training *should* be in place to ensure compliance with the regulations and indicate a proactive approach to environmental damage avoidance.

Voter Summary

Unanimous.

Dissenting Opinions

Not applicable.

4.10 CUSTOMER OBLIGATIONS TO A UTILITY DISTRIBUTION SYSTEM AND UTILITY EQUIPMENT

[FINALIZED: FEBRUARY 8, 2000]

Issue Statement

The condition of customer owned distribution equipment and the operation of this equipment can adversely affect the reliability or operation of a utility's distribution system and consequently affect the reliability of service and quality of power to other customers. It is also a common practice for distribution utilities to have distribution equipment on, over or under customer property. The issue is:

> What are a customer's obligations with respect to distribution system equipment on the customer's property?

Options

1. **Minimalist Approach:** No customer obligations, assume that the Electrical Safety Authority will ensure that all customer installations and actions will not adversely effect the reliability or operation of a utility's distribution system.

2. **Prescriptive Approach:** The DSC will specify what obligations customer's have with respect to maintaining their electrical equipment in a condition that does not adversely effect the reliability or operation of a utility's distribution system.

3. **Modified Prescriptive Approach:** The DSC will provide direction that ensures customers maintain their electrical equipment in a condition that it does not adversely effect the reliability or operation of a utility's distribution system.

Background Information

Customer owned equipment such as overhead and underground primary lines, substations and other equipment that is directly connected to utility distribution systems can have an adverse affect on the reliability and operation of the overall system if they are not maintained in a good working condition. Similarly, the actions of a customer's operation could have an adverse effect on the power quality of a distributor's distribution system. Electrical loads such as large motors, arc furnaces, large welders etc. can have far reaching and potentially adverse affects on a distribution system and can take considerable time and cost to implement equipment and/or methodologies to mitigate the disturbances.

Once the boundary from distribution system to customer system is crossed, the Electrical Safety Authority has the responsibility for standards and inspection of customer owned equipment. Presently it usually takes a combined effort of the distributor, the Electrical Safety Authority and the customer to source and correct customer-caused disturbances. With the change in statutes, there may be some distributor protection lost with regards to damage to utility equipment caused by a customer.

Implementation Issues

Some customers may be subject to maintenance activities to which they are not accustomed. There may be costs associated with this practice.

Summary of Discussion

Issues from the group discussion include the following:

- Customers with primary voltage equipment should be obligated to maintain their equipment on a regular and ongoing basis to avoid adverse effects to utility distribution systems. The type of equipment is typically primary overhead or underground lines, substations, high voltage switching devices and other like equipment. A catastrophic failure on customer owned equipment can operate fuses/breakers upstream on a utility distribution system and thus interrupt power to other customers or “bump” the circuit. Proper fuse coordination on customer owned equipment should prevent this in most cases and is a matter for the Electrical Safety Authority.

- The Electrical Safety Authority does not require customers to perform and record routine inspections and maintenance on their electrical distribution equipment. However once a customer has had a substation or like piece of equipment out of service for the purpose of maintenance and/or repair an inspection/observation sheet must be filled out and filed with the Electrical Safety Authority. Any defects found that are urgent in nature must be repaired immediately; non-urgent defects may be repaired at a future date.

- Lack of routine inspection and maintenance can lead to situations whereby a customer’s equipment can become a hazard to the public and/or adversely affect the reliability of the distributor's distribution system. If a customer does not follow acceptable inspection and maintenance routines and their equipment is adversely affecting a utility distribution system and other customers, the utility should have the authority to disconnect their service until corrective measures are taken.

- Historically, customers with primary voltage equipment have not always had a fused disconnect device at the point of demarcation. For example, 44kv services are typically tapped with mechanical clamps and no fusing at the point of demarcation. In more recent years some utilities have been requiring customers to provide fused, gang operated switching devices on certain voltages. Although this may seem like a good idea, it may not always be in the best interest of the customer and/or the utility due to technical complications such as ferro-resonance at the 44 kv level.

- The group felt that the DSC should not directly impose customer obligations. However, it may allow the distributor flexibility to impose requirements on customers through the Conditions of Service and/or Connection Agreements.

Recommendation

Option 3: the Modified Prescriptive Approach is recommended. The DSC should provide direction that allows distributors to address issues of customer obligations and take appropriate actions through the Conditions of Supply and/or Connection Agreements.

The Conditions of Service document and/or Connection Agreement may contain direction on the following:

Distribution utilities should have the authority to direct a customer to take corrective action on the customer's distribution system when there is a direct hazard to the public or the customer is causing or could cause adverse effects to the reliability of a distributor's distribution system. In the event that the customer does not take the corrective action in a timely fashion, the distributor may disconnect service to the customer until corrective action is taken.

NOTE: Refer to the Disconnection of Service section of the code for utility rights and obligations in regards to disconnection of service.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.11 DISTRIBUTORS' OBLIGATIONS REGARDING CUSTOMER PROPERTY

[FINALIZED: FEBRUARY 9, 2000]

Issue Statement

It is common practice for distributors to have distribution equipment on, over or under customer property. From time to time, a distributor is required to enter onto customer property to operate, maintain, repair or replace distribution plant and equipment. Distribution companies typically act in good faith and restore customer's property to the same, or as near as possible the same condition it was in prior to the work being performed by a distribution company. The issue is:

What are a distributor's obligations regarding customer property?

Options

1. Assume that all distributors will always return a customer's property to a pre-work condition following any work performed by the distribution company and remain silent on the issue.

2. Specify what the obligations will be for distributors to restore customer property after the distribution company performs work on a customer's property.

3. Provide direction that ensures distributors act in good faith and restore customer property to the condition that it was in prior to the distribution company performing any work, in accordance with the provisions of Section 40 of the *Electricity Act, 1998*.

Background Information

Historically, there were no regulated obligations for distribution companies regarding restoration of customer property. Common sense dictated that a distribution company would repair or replace any customer property that was damaged during the undertaking of work on customer property.

For example, prior to the work starting, a distributor would notify the customer of the nature of the work, project duration and the type of possible damage that might occur. If a customer's lawn and/or bushes were damaged during a construction project, the distributor would undertake to repair or replace the damaged area in the yard and replace any destroyed landscaping.

New legislation provides specific guidance regarding the issue. Section 40 (1) of the *Electricity Act, 1998* empowers a distributor to "at reasonable times, enter land on which its distribution system is located to inspect maintain repair, alter, remove . . ..wires or other facilities to distribute electricity." Section 40 (8) obligates the distributor to "provide reasonable notice", "in so far as is practical, restore the property to its original condition", and "provide compensation for any damages caused by the entry".

The Model Franchise Agreement utilized in the natural gas industry is silent on the issue of restoration of customer property (the issue may be addressed elsewhere). Restoration of site provisions in the Model Franchise Agreement pertain to restoration of public roads & highways to the satisfaction of the road authority.

<u>Implementation Issues</u>

Section 40 of the *Electricity Act, 1998* is detailed in its provisions regarding a distributor's rights and obligations associated with entry to enter land upon which its distribution plant is located and restoration of property after work is carried out. Provisions within the DSC are required to enable mitigation of unreasonable distributor expense in restoring customer property following work on the distribution system.

<u>Summary of Group Discussion</u>

Registered Easements and Right-of-Ways

A typical registered easement would contain a clause or clauses that describe the distributor's rights and responsibilities, including the type of plant, access, keeping the easement clear of trees etc. and that the distributor has right of access to the easement at all times. Also included in the easement are the landowner's rights and responsibilities, including keeping the easement free and clear of any trees, buildings, structures, obstructions and that the landowner not damage any property of the distributor. Individual distributors may negotiate specific details into the registered easements as they see fit. Non-registered easements are less clear and may be as simple as a signed letter stating that the distributor may install and maintain specific distribution equipment (e.g. a pole and anchor).

Unregistered Easements

Unregistered easements are typically a less sophisticated and cheaper method of obtaining landowner approval for installing distribution equipment. A typical application would be for installation of an anchor, pole and anchor, or a transformer or switching device on the edge of a customer's property. The method of recording and types of details in unregistered easements may vary greatly between utilities. An unregistered easement may contain a simple diagram showing the easement area and the type of equipment being installed. Both the landowner and the utility would sign-off the document based on the understanding of any terms negotiated. These documents usually do not go through lawyers nor are they registered at the local registry office.

Customer Obligations

What are the obligations of a customer if a distributor has to come onto their property to dig, smash, break, remove customer property to undertake repairs to distribution equipment? For example, it is quite common for distributors to have distribution plant in older subdivisions that is at the back of a customer's house or property. Over the years the customer has spent considerable time and money building decks, patios, fences, gardens, structures etc. that are now over top of the service cables. Presently, utilities negotiate with the landowner the terms for the work that will take place. Negotiations could include who will be responsible for the cost and repair/replacement of expensive landscaping, fences buildings etc. and who will perform the particular tasks. Where there is only sod, the utility usually returns the work area to a condition similar to what it was in prior to the work being performed.

Storm Damage

Damage to distribution plant caused by storms can sometimes come from a customer's property. For example, a storm causes a large tree limb or entire tree that is situated on a customer's property to damage distribution equipment. In the process of restoring power, the distributor typically will remove enough of the tree to make the necessary repairs and leave the site in a safe condition. The responsibility for cleaning up and removing the debris lies with the customer, not the distributor.

Task Force members noted that the phrase "in so far as practical" in section 40 (8) of the Electricity Act leaves some room for interpretation. For instance, can cost be considered an aspect of practicality? The opinion was expressed that some provisions within the DSC are required to enable mitigation of unreasonable distributor expense in restoring customer property following work on the distribution system in situations where the customer has erected structures or extensive landscaping over buried distribution plant.

Recommendation

Option 3 is recommended.

1. Prior to starting any maintenance work on a customer's land, building, facility or property, a distribution company must notify the customer regarding the type of work that will take place. Upon completion of the work the distribution company shall be responsible, in so far as practical, for restoring the customer's property back to the condition it was in before the work took place and provide compensation for any damages caused by the entry, in accordance with Section 40 of the *Electricity Act, 1998*.

2. The DSC should empower the distributor to include appropriate statements within its Conditions of Service to mitigate exposure to unreasonable expense in the restoration of customer property

3. The distributor should have the right to select an alternative repair methodology to minimize the cost of restoration of customer property.

4. Where formal easements or permissions exist, the terms of access (if any) and established law will be followed regarding restoration of customer property.

5. Where no utility easement rights exist or a customer has built structures or extensive landscaping on or over the distribution plant, the utility and the customer will negotiate terms and conditions for removal, restoration, repair or replacement of the structure or landscaping and associated costs prior to any work taking place.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.12 DISTRIBUTOR OBLIGATIONS REGARDING RELOCATION OF DISTRIBUTION PLANT

[FINALIZED: FEBRUARY 23, 2000]

Issue Statement

This summary discusses distributor obligations regarding relocation of distribution plant when requested by another party. The issue is:

> What is a distributor's obligation to relocate distribution plant?

Options

1. Distributors should be obligated to comply with any request to relocate its plant.
2. Distributors should be free of any obligations regarding relocation of distribution plant.
3. The DSC should rely on the existing body of legislation and law to govern relocation of distributor plant.

Background

There are several scenarios where a Distributor may be requested to relocate distribution plant by another party, as described below.

Road Authority Request

Distributors may be requested to relocate distribution plant by the local road authority to facilitate a road widening or other road improvement. The road authority is the body responsible for the provision and maintenance of the public road allowance and may be the local municipality, region, county or provincial Ministry of Transportation. A road authority relocation request may pertain to utility duct structures that are attached to or located within bridges that the road authority wishes to rehabilitate or rebuild.

Other Utility Request

Distributors may be requested to relocate plant by other utilities or distributors occupying the public road allowance. An example would be a request by the gas utility for the distributor to relocate a pole line in order to facilitate installation of a new gas main where no gas service had previously been provided.

Request by Joint Use Party

Distributors engage in joint use of poles and underground structures with other parties. In these situations one party leases, at a negotiated rate, access to the pole or underground structure at terms outlined in a formal agreement. In some cases a formal written agreement may not exist.

Request by Private Property Owner/Customer

There are several possible scenarios where a private property owner may request relocation of distribution plant:

- Distribution plant is located on the public road allowance adjacent to the customer's property.
- Distribution plant serving several customers is located on the private property of the party requesting the relocation. A registered easement may or may not exist.
- Distribution plant located on private property provides service only to the party requesting the relocation.

Request by Railway or other Party having Jurisdiction over the Land

Distributors also locate plant on rights-of-way under the control of other parties such as railway companies, government agencies and other parties. Generally, the terms of access including potential relocation of plant, are set out in some form of agreement.

Public Service Works on Highways Act

The Public Service Works on Highways Act outlines provision of notice, timing, and cost sharing associated with road authority projects that entail removal or relocation of distributor plant. It may be worthwhile to note that this Act refers to the owners of utility works as "operating corporation" and defines this term to include a "municipal corporation, commission, company or individual operating distributing or supplying electricity." Based on this definition, the Public Service Works on Highways Act applies to distributors.

Section 2 (1) of the Public Services on Highways Act states that the road authority may, by written notice, require a distributor to remove or relocate distribution plant located on the public road allowance to facilitate road constriction or improvements.

Section 2 (2) makes provision for the road authority and distributor to negotiate cost sharing arrangements for the relocation of the distributor's plant. In the absence of any agreement between the road authority and distributor, the default cost sharing arrangement is for the road authority to pay 50 percent of labour and labour saving equipment to relocate the distributor'' plant.

The Act also includes a process whereby disputes can be referred to the Ontario Municipal Board.

Other Legislation

In addition to the PSWHA, there is other legislation and associated regulation and case law pertaining to the issue (e.g., Land Titles Act, Registry Act, and Highway Improvement Act).

Implementation Issues

None identified.

Summary of Discussion

The Task Force recognized that there is a substantial body of law dealing with a distributor use of the public road allowance, access to private property, registered and unregistered easements, and use of other rights-of-way such as Railway. In many cases where distributors install plant on the rights-of-way of other parties, there may be formal agreements in place that provide guidance on the issue of relocation of plant.

The consensus is to rely on the existing body of law rather than detailing specific obligations within the DSC. It was also noted that situations may arise that are not covered by existing law. In these cases a distributor should not be specifically obligated to relocate but should be obligated to respond to the request and make reasonable efforts to resolve the issue with the other party, including recovery of costs on a fair and reasonable basis.

Recommendation

Option 3 is recommended.

1. Distributor rights and obligations regarding relocation of distribution plant when requested by another party will be in accordance with the existing body of legislation, regulations, formal agreements, easements and law.

2. In the absence of legislation, case law or formal agreements to cover a particular situation, the DSC should not obligate distributors to relocate plant when requested by another party. However, the distributor should be obligated to attempt to resolve the issue in a fair and reasonable manner. This will include providing a reply to the other party that indicates whether or not the relocation is feasible and may also include cost recovery on a fair and reasonable basis.

3. In addition to the protection of existing legislation and case law, customers will have access to the distributor's dispute resolution process as stipulated in the Transitional Distributor Licence.

Voter Summary

Unanimous.

Dissenting Opinions

None.

4.13 PLANNED INTERRUPTIONS

[FINALIZED: MARCH 7, 2000]

Issue Statement

This summary of recommendation covers a distributor's obligations under the DSC regarding planned interruptions.

Options

1. Policies covering planned interruptions would be covered by individual distributors in their conditions of supply.

2. Planned interruptions would be covered in a common manner as outlined in the DSC

Background Information

Currently, distributors have varying planned interruption policies that may be documented in their conditions of supply or as company policy.

Summary of Discussion

The group felt that there may be some advantage to having some consistency for planned interruption situations. However, there may be situations due to system design and operation that may make common conditions difficult or overly costly for some distributors or customers.

Planned interruption policies should be available to the public in the DSC or distributor conditions of supply to identify expectations and reduce customer complaints.

The group felt that due to variance in past practice and varying customer requirements in different regions, it was desirable to leave some discretion to the distributor to set these guidelines. Conditions of supply could be better amended as local business conditions change.

All efforts to maximize the notice period should be undertaken by the distributor to allow customers to mitigate the impact of the planned outage. The duration and frequency of planned outages should also be minimized through scheduling and the design of the distribution system, where possible.

Recommendation

It is recommended that planned outage procedures should be listed in the individual distributors'

Conditions of Service. Notice periods should be as long as possible, while the duration and frequency of planned outages should be minimized for a particular customer.

Voter Summary

Unanimous

Dissenting Opinions

None.

4.14 STANDARD VOLTAGE OFFERINGS

[FINALIZED: SEPTEMBER 15, 1999]

Issue Statement

The Distribution System Code (DSC) will contain minimum requirements for distributors related to their distribution system. The issue is:

> Should a distributor be required to provide supply at a minimum set of voltage levels?

Options

1. Each distributor is allowed to define the voltage levels the distributor offers to customers and must notify customers about the offered voltage levels.

2. The DSC defines a minimum set of voltage levels that a distributor must offer and provide to customers.

3. The DSC defines a comprehensive set of voltage levels and requires each distributor to offer at least a certain number of options, the levels of which are chosen by the distributor.

Background Information

Distributors supply electricity at various voltage levels. Offerings vary across distribution systems. In some areas, commercial and industrial customers can obtain high voltage levels (e.g., 44 kilovolts); other areas only provide residential voltage levels (e.g., 240 volts). In addition, some distributors provide a variety of offerings whereas others only provide a single voltage level.

It was suggested that certain voltages should be offered throughout the Province. The DSC could contain a minimum requirement of which voltages should be provided by each distributor. This requirement would create standardization across the Province in terms of service offerings. Electricity users would be assured that they could receive certain voltages regardless of the distribution service territory. However, this suggestion poses many issues.

Implementation Issues

All distributors may not be able to provide a required set of voltages. Alternatively, it may be too costly or physically impossible to offer the required set of voltages without jeopardizing the reliability of the distribution system.

Summary of Discussion

Currently, distributors choose the voltages that are offered to their customers. In some instances, a customer may desire a different voltage and request that the distributor provide it. The distributor has the choice of providing this new voltage, and most likely would charge the customer for any additional equipment that is required to supply the new voltage.

If a minimum set of voltages is required, distributors may not be able to meet the requirement. For example, some distributors provide voltages of 34.5 kv that is standard in the United States. Other distributors provide voltages common in Ontario of 27.6 kv or 44 kv. A distributor that provides 27.6 kv would be unable to offer 34.5 kv without dramatically reconfiguring its distribution system. Furthermore, certain voltages may affect the reliability of the distribution system.

If certain voltage levels are not required, there is a potential for gaming by distributors. Distributors may take advantage of new customers who request different voltages, even if the distributors already were intending to incorporate new levels into their system. This potential for gaming, however, was considered to be an issue related to expansions and better dealt with by the DSC under that topic.

Some distributors may not provide certain voltage levels and may not wish to do so. These distributors require protection from customers who would demand the voltage level that is not provided. One solution is to require distributors to notify customers regarding which voltage levels are offered and describe the conditions under which a customer may obtain a voltage level that currently is not provided. This approach may become extremely complex, however, if a distributor provides a certain voltage level in one part of the distribution system, but not in the other. A distributor should not be required to map out where each voltage level is provided.

The decision to provide a certain voltage level could be considered a business decision that a distributor should make. If a voltage level is technically achievable, a customer is willing to pay for the equipment, and the costs or impacts imposed on the system or staff are acceptable to the distributor, a distributor may choose to provide the voltage level to the customer. Distributors who can offer certain voltages may have a competitive advantage over others. These competitive advantages should be exploited for the purposes of better rationalization of Ontario's distribution systems.

Recommendation

Option 1 is recommended. A distributor should be able to determine the voltages that it offers. Distributors should be required to notify customers (e.g., through a Condition of Service document) which voltage levels are offered by the distributor and whether customers may request additional voltages if they are willing to pay for those voltages. Instead of detailing where each voltage is available, the notification may include caveats that certain voltage levels may not be offered throughout all parts of the distribution system.

Voter Summary

Unanimous.

Dissenting Opinions

None.