DISTRIBUTION SYSTEM CODE TASK FORCE

CHAPTER 2

SUMMARIES OF RECOMMENDATIONS: CONNECTIONS, EXPANSIONS, AND REINFORCEMENTS

TABLE OF CONTENTS

2.1 WHEN A BUILDING "LIES ALONG" A DISTRIBUTION LINE – THE FORMAT THE DEFINITION SHOULD TAKE

[FINALIZED: JULY 5, 1999]

Issue Statement

Transitional Distribution Licenses issued by the Ontario Energy Board (OEB) include the obligation to connect if the building lies along any of the lines of the distributor's distribution system and the obligation to offer to connect if the building is within the distributor's service territory (sections 13.1 and 13.2).[1] The terms of such connection or offer to connect shall be made in accordance with the Distribution System Code and Rate Handbook.

The distinction between the obligation to connect and the obligation to *offer* to connect is differentiated by whether the building lies along any of the lines of the distribution system. Thus, it is important to determine:

> When does a building "lie along" a distribution system, thereby requiring a distributor to connect versus make an offer to connect?

Options

1. Allow each distributor to define when a building "lies along" its distribution line and obtain approval from the OEB on a distributor-by-distributor basis. The OEB will maintain a list of approved definitions for each distributor.

2. Make a single definition that applies to every distributor. For example:

    a. Requires no more than 100 feet of secondary wire to connect the building to the distribution line.

    b. Requires no more than three poles to connect the building..

3. Develop a general definition under which each distributor can develop its own practice with respect to equipment and expense required for a connection. For example:

    a. Building is within 100 feet of a distribution line.

[1] In addition, the owner, occupant or other person in charge of the building must request connection in writing.

b. A connection would cost the distributor less than $100 in labor and equipment to connect the building to the distribution line.

c. None of the equipment, material and devices required to supply electricity to the building would provide conductivity to the main circuits and would not be used to provide electrical energy to another building.

Background Information

In the past, distributors exercised discretion with regard to the obligation to connect. For example, in some municipalities, connection could include the addition of as many as three new poles. In other municipalities, connection obligations were defined to include no more than 100 feet of secondary wire. Anything beyond these limits was considered an expansion of the existing distribution system, and the costs were incorporated into base rates rather than connection fees.

The Market Design Committee's Retail Technical Panel (RTP) examined the issue of what should determine whether a building "lies along" a distribution line. The RTP suggested that three approaches could be used for the purposes of determining whether a building "lies along" an existing line:

1. the adoption of historic definitions in accordance with the practices of each distributor;

2. the establishment of one standard definition that would determine whether a building "lies along" an existing line within the meaning of section 28 of the *Electricity Act, 1998*, or rather requires approval for an expansion as described in section 92 of the *OEB Act, 1998*; or

3. the establishment of guidelines for use in ascertaining which undertakings are to be considered connections and which are to be considered as expansions.

The RTP determined that the first approach would impose a regulatory burden and create potential inconsistencies with other aspects of the regulatory system (e.g., rate recovery) and the second approach would be too restrictive given the diversity of geography and distribution system characteristics across the Province. The RTP recommended that general guidelines be established to allow each distributor the flexibility to define its obligation to connect according to whether or not the connection falls within those guidelines. Monitoring could be performed by the OEB on the basis of complaints filed by consumers.

Implementation Issues

Implementation issues include regulatory burden and potential difficulties for distributors.

Allowing each distributor to define its own definition of connection allows distributors to operate as they have, but could create a large regulatory burden. Making a strict definition may pose implementation difficulties for certain distribution systems. For example, a definition of less than three poles does not consider underground systems. Thus, some distributors may have difficulty implementing a single definition that is applied to the province. General guidelines serve to reduce regulatory burden and allow distributors a certain amount of flexibility to meet the specific needs of their system. It also creates a general consistency across the province. This consistency could be reinforced by general rules related to cost recovery and allowed rates. For example, if the Rate Handbook only allows a connection charge that recovers the incremental cost of connecting a building up to a certain limit, distributors most likely would define what “lies along” the line in order to ensure a consistency with rate recovery.

Summary of Discussion

The discussion was broken up into two topics. The first was, as a general approach, how do we wish to define “lies along.” It was noted that the definition of “lies along” will interact with the cost recovery mechanism established in the Rate Handbook. Thus, even if a general set of guidelines was set, the rate recovery mechanism could create incentives so that each distributor converged to a similar definition. Although this creates a chicken and egg problem, in that either could be created first, the DSC members agreed that rates and cost recovery in the Rate Handbook should be driven by the technical definition that the DSC develops.

Recommendation

Option 3 was recommended. The definition of “lies along” will be a general definition under which each distributor can develop its own practice with respect to equipment and expense required for a connection.

Voter Summary

Unanimous.

Dissenting Opinions

None.

2.2 DEFINITION OF "LIES ALONG"

[FINALIZED: JULY 5, 1999]

Issue Statement

The DSC already has addressed the format that the definition of "lies along" should adopt. By a unanimous vote, the DSC decided to create a general definition under which each distributor can develop its own practice with respect to equipment and expense required for a connection.

Transitional Distribution Licenses issued by the Ontario Energy Board (OEB) include the obligation to connect if the building lies along any of the lines of the distributor's distribution system and the obligation to *offer to connect* if the building is within the distributor's service territory (sections 13.1 and 13.2).[2] The distinction between the obligation to connect and the obligation to *offer* to connect is differentiated by whether the building lies along any of the lines of the distribution system. Thus, it is important to determine:

> When does a building "lie along" a distribution system, thereby requiring a distributor to connect versus make an offer to connect?

This distinction is important because it will determine whether a customer's request to a distributor for connection requires OEB approval, or can be performed independent of the OEB in accordance with the technical requirements of the Distribution System Code and charged according to the Rate Handbook.

Options

1. Definition that parallels the definition of "connection":

   A building "lies along" a distribution line if the building can be connected to a supply of electricity using only equipment, material and devices dedicated to the supply of electrical energy to a single property, none of which provides current carrying capacity to the main circuits on a road allowance or easement that has the potential to provide electrical energy to present or future customers.

   Alternative: A building "lies along" a distribution line if it only requires a connection in order to receive a supply of electricity.

[2] In addition, the owner, occupant or other person in charge of the building must request connection in writing.

2. Definition that references system requirements and limitations:

   A building "lies along" a distribution line if a connection can be made in accordance with the Distribution System Code and meets the conditions listed in the distributor's Conditions of Service.

3. Definition that defines by exclusion:

   A building "lies along" a distribution line if it can be connected to a supply of electricity without an extension, upgrade, reinforcement or expansion.

4. Historic Legal Definition

Background Information

Section 28 of the *Electricity Act, 1998* requires a distributor to connect a building that "lies along any of the lines of the distributor's distribution system." The interim distribution licenses differentiate between a building that "lies along" a distribution line and any other connection which requires an "offer to connect." The *Act* requires OEB approval for any construction, expansion and reinforcement of a distribution system (The *Ontario Energy Board Act, 1998,* sections 92(1)).

It is important to define when a building "lies along" a distribution system for two reasons. First, a building that "lies along" a distribution system can be connected without requiring an OEB hearing that is required for construction, expansions, and reinforcements. An appropriate definition would facilitate new service and minimize regulatory burden. Second, if a building lies along a distribution system, a distributor is required to connect, whereas a distributor must simply "offer to connect" any building in the service territory that is not along a line. The offer to connect implies that the connection requires something in addition to a feeder line such as a reinforcement or expansion. Thus, the distinction is important for determining how pricing should be imposed.

Implementation Issues

Implementation should be relatively easy once terms are defined and rate recovery rules are applied. However, there may be implementation issues if the technical definition and the rate recovery rules do not correspond. In this case, distributors will either over collect for a simple connection or under collect for a definition that implies more work than is envisioned in the rates. If rates do not correspond to the cost of connection as connection is defined, then a distributor may face inappropriate incentives. The DSC decided to define the technical term and propose this definition to the Rate Handbook effort so that charges and rates can be set according to the technical requirements of a connection as delineated in the DSC definition.

Another implementation issue is with respect to the requirement that the OEB approve all construction, expansion and reinforcement of distribution systems, with limited exceptions. This requirement creates an onerous burden on both the regulator and distributors. A broad definition of "lies along" may counteract this burden. Alternatively, embedding reinforcement into a definition of connection may achieve the opposite effect and require OEB approval of what has been defined as a connection, simply because it includes a reinforcement or expansion component.

Summary of Discussion

Having agreed to use a general definition that would apply to all distributors, discussion turned towards what the definition of "lies along" should be for purposes of the Code. It was agreed that the definition should be consistent with the work that had been done on the definition of connection, reinforcement, expansion and upgrade. This lead to a proposed definition that paralleled the definition for connection (option 1).

Working from this definition, it was noted that not all buildings that "lie along" a distribution line could be connected to that line. For instance, the distribution line may not have sufficient capacity or may actually be a transmission line that is included in the distribution system. A distributor should not be required to connect if it is unsafe or bad for the system. There are two ways to ensure that a distributor does not have to connect a building that lies along a line if the connection would conflict with reliability requirements or Conditions of Service:

1) Incorporate a reference to Conditions of Service in the definition of "lies along" (option 2).

2) Define "lies along" but place limitations on the obligation to connect by saying a distributor does not have the obligation to connect a building that lies along its distribution system line unless the connection is consistent with the distributor's Conditions of Service.

The discussion often branched into other areas beyond simply defining "lies along." This demonstrates the impacts that the definition would have on many other aspects of the Distribution System Code. Given this complexity, it was suggested that "lies along" be defined as anything that does not require an expansion, reinforcement or upgrade (Option 3). One of the potential problems with this is that each of these terms can be defined with respect to the others. It will be important that the final Code not be a set of circular definitions.

With respect to option 4, it was noted that a term similar to "lies along" was in the old Public Utility Act. Section 55 of the *Public Utility Act* states:

> (1) Where there is sufficient supply of the public utility, the corporation shall supply all buildings within the municipality situated upon land lying along the line of any supply pipe, wire or rod, upon the request in writing of the owner, occupant or other person in charge of such a building.
>
> (2) subsection (1) does not apply with respect to natural gas.

(Emphasis added).

Counsel also researched any court cases in which the term “lies along” was more fully defined. In general, there are no court cases that are binding or relevant for purposes of the Distribution System Code. No case law specifically deals with the meaning, although several cases include reference to the term. Thus, the plain meaning of the work would hold (i.e., “contiguous” or “abuts”).

Lessons from Ontario’s Gas Distribution Industry

In Ontario’s gas distribution industry, the term “lies along” is defined as property that abuts or is contiguous with supply. Each utility has defined the specifics differently, usually as property that can be connected with less than 20 to 30 meters of pipe. However, the definition does not preclude connecting a customer that requires more than 20 to 30 metres. If there is a connection that requires more than that amount, gas distributors ask for a contribution from the user.

The gas situation may not be directly applicable to electricity. Gas companies have been operating under cost of service regulation and have tried to expand the rate base as quickly as possible. Performance based rates would create different incentives, especially with respect to recovery of connection costs versus recovery through distribution rates.

Absolute Values were Rejected

For the most part, the DSC shied away from setting absolute values in the definition. Distance limits such as 100 metres of secondary wire and cost limits seemed too restrictive given the diversity of distributors. It was noted that one of the strengths of choosing a general definition is that it allows each distributor to define a connection according to its own criteria (e.g., length of wire or cost) in its Condition of Supply. The Code should not prescribe one length and prevent distributors from being able to achieve their own economies. The Code should promote real economies. However, the Committee should be aware of potential regulatory diseconomies. Thus, although the Code might include a general definition, each distributor could further define “lies along” for its distribution system so long as it was consistent with the general definition in the Code.

Point of Demarcation

It was noted that the definition of "lies along" may be affected by the point of demarcation. The point of demarcation will define where a distributor's obligation ends. Does the distributor have the obligation to connect a building, or only provide supply up to the property line? Although the definition of a point of demarcation will affect how "lies along" is measured, it is an issue that is directly relevant to the definition of a connection, and only indirectly affects the definition of "lies along." This issue will be addressed later when connection is defined and changes associated with a connection are determined.

Obligation to Connect a Building

The *Act* describes a distributor's obligation to connect a building. However, a building may not properly describe all situations which require connection. For example, a billboard or streetlight is not a building. The Committee agreed that despite the literal obligation, the spirit of the *Act* would require a distributor to connect these facilities. Thus, it was agreed that the definition of building either should be expanded to be more general or the term "facilities" should be incorporated into the definition of "lies along."

Another issue with respect to a building is whether a subdivision is considered a single connection or separate connections for each building. Currently, a subdivision usually entails a single connection; the developer is responsible for supply from the connection point to each of the buildings. If a subdivision "lies along" a distribution line, is the distributor obligated to connect the subdivision or every building in the subdivision? Incorporating the term "facility" would address this issue.

<u>Recommendation</u>

The Committee agreed to define "lies along" in accordance with option 2, modified to address the concept of a facility:

> A building or a customer facility "lies along" a distribution line if a <u>connection</u> can be made in accordance with the Distribution System Code and meets the conditions listed in the distributor's Conditions of Service.

The definition of connection will be defined elsewhere in the Code.

<u>Voter Summary</u>

Unanimous.

Dissenting Opinions

None.

2.3 A DISTRIBUTOR'S ABILITY TO DENY CONNECTION

[FINALIZED: FEBRUARY 22, 2000]

Issue Statement

Section 28 of the *Electricity Act, 1998* requires a distributor to connect a building that ?lies along any of the lines of the distributor?s distribution system.? In a prior summary of recommendation, the Distribution System Code Committee suggested a definition for "lies along" that would impose a limiting condition when a building or a customer facility ?lies along? a distribution line. Under the recommendation, a connection would be made only if it could be made in accordance with the Distribution System Code (DSC) and meets the conditions listed in the distributor?s Conditions of Service document. The issues are:

> What are the conditions under which a distributor is not required to connect a building that lies along a line in its distribution system?
>
> What are a distributor's obligations with respect to a building that a distributor is not obligated to connect?

Options

The options concerning conditions under which a distributor is not required to connect a building that lies along a line could be either clearly defined or left to distributors:

1. List specific conditions in the DSC under which a distributor is not obligated to connect.

2. Provide principles in the DSC that a distributor must follow in determining whether it is obligated to make a connection.

3. Allow each distributor to determine and define specific conditions under which they will not make a connection.

With respect to the request to connect, the following options describe potential obligations of a distributor who refuses connection:

4. A distributor has no obligation whatsoever to connect a building that does not meet identified conditions.

5. A distributor must identify the reasons for not connecting and has no obligations to do additional work until the person requesting the connection remedies the problem.

6. A distributor must make an offer to connect that identifies the reasons for not connecting

and include an estimate of the cost the distributor would charge to remedy the problem to make the connection. If the distributor is unable to remedy the problem, it is the responsibility of the customer to do so before a connection can be made.

Background Information

The *Energy Competition Act, 1998* lists several goals that directly impact distributors:[3]

- To facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition;
- To provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario;
- To protect the interests of consumers with respect to prices and the reliability and quality of electricity service;
- To promote economic efficiency in the generation, transmission and distribution of electricity; and
- To facilitate the maintenance of a financially viable electricity industry.

The *Act* also delineates a distributor's obligation to connect or offer to connect any building in its distribution system. These obligations have been incorporated into the transitional distributor licenses and are likely to be included in the end-state licenses.

Implementation Issues

The spirit of the *Energy Competition Act, 1998* is to ensure that all customers who wish to receive electricity have the opportunity to do so. However, the *Act* also identifies other goals that may be in conflict with providing electricity to all customers who wish to receive it. For example, safety, reliability and efficiency of a distribution system may be jeopardized by a single connection.

Conflicts inherent in the *Act* may create uncertainty and risk for a distributor. If a distributor denies connection in order to comply with other goals, the distributor may be brought to task for not complying with its licence. For these reasons, it is important to clearly document a distributor's right to refuse connection.

Resolution of this issue must strike a fine balance between the conflicting goals in the *Act* and the need to protect distributors and potential electricity consumers.

[3] *Electricity Act, 1998*, sections 1(a) - 1(f), excluding section 1(e) which refers to Ontario Hydro's debt. Similar purposes are listed in the *Ontario Energy Board Act, 1998*, section 1.

Summary of Discussion

The general approach in DSC decisions has been to provide distributors with autonomy to define their specific conditions, but require documentation. In this instance, there may be a stronger need to provide stronger guidance on principles that a distributor must follow in defining conditions under which it is not obligated to connect. Allowing a distributor to define these conditions in its Conditions of Service without explicit support of the DSC may result in litigation or regulatory oversight that otherwise would be unnecessary.

There are certain principles that have been identified for distributors in prior discussions. These principles may define broad conditions under which a distributor may refuse connection. A distributor would determine on a case-by-case basis whether the principles applied and could define situations that fall under each principle in more detail in its Conditions of Service.

A distributor that follows these principles and refuses a connection would not be in violation of its license or legislation so long as the distributor could show that the connection would violate one of the principles. Examples of these principles and situations that would violate them are described below.

Compliance with Legislation - As noted, a distributor's obligation to connect may violate other aspects of the *Act*. A generator should not be forced into contravention of conflicting requirements. More generally, a distributor should not be forced to violate laws in Canada and the Province of Ontario. For example, a distributor should not be forced to make a connection to a building that is in violation of the building code or implicated in unauthorized use of energy. More specifically, a distributor should not be forced to make a connection that would result in a violation of its condition of licence (i.e., the customer is outside of its service territory).

Public and Worker Safety - Conveyance of electricity poses safety risks. There are ways to mitigate safety risks to workers and the public. The DSC addresses safety issues in another summary of recommendation. In addition to safety hazards related to the distribution system, a connection may impose an unsafe worker situation beyond normal risks inherent in the operation of the distribution system. For example, a customer may pose a danger to a worker entering the property in order to make a connection (e.g., the potential consumer wields a gun or has a dangerous pet).

Reliability and Efficiency - Distributors will operate under performance-based rates (PBR) and may be penalized based on measures of their efficiency and reliability. It would not be fair to require a distributor to connect a building that poses potential harm to its distribution system. In particular, there may be buildings that could cause the system to trip or brown-out if connected without proper protection. Another dilemma occurs if a customer requests connection to a line that is not capable of providing electricity to the customer or is not intended for that use (i.e., a dedicated feeder line). A distributor should not be required to make a connection that adversely affects its system.

No Cross-Subsidization - Aside from a potential adverse effect on the distribution system, which would affect all customers, a single connection may directly affect another customer. For example, connection of a customer may have adverse affects on the voltage or harmonics of another connection on the same line. Rights of existing customers should take precedence over new connections, or a mutually acceptable remedy should be implemented.

Non-discriminatory Access - A distributor is required to offer non-discriminatory access to generators, retailers and consumers. In other words, a distributor should not make a connection that would be discriminatory. If a retailer requests discriminatory access, a distributor should be able to refuse connection until the proper procedures have been accomplished.

Payment in Arrears - A distributor may disconnect a customer for non-payment for distribution services or electricity supplied under section 29 of the *Electricity Act, 1998*. *The Electricity Act, 1998* allows distributors to collect the money in arrears even if a customer is disconnected. It seems to be in keeping with legislation to allow a distributor to refuse connection if the person requesting the connection owes the distributor money for distribution services or electricity supplied under standard supply service.

Other - A distributor should be able to identify other conditions consistent with these principles in its Condition of Service document.

Customers with no direct access to a distribution line (i.e., no easement to allow a connection) pose another issue. There are existing connections that are attached to the distribution system by a feeder that runs through another person's property. There may be no official easement or written agreement by the property owner who allows the right-of-way. With respect to new connections, a potential customer may appear to lie along a line, but have no direct access because another person's property lies between that potential customer and the line. The issue of whether a distributor may deny connection to a person who does not have an easement may be moot. That person simply does not "lie along" the distribution line and a distributor is obligated to make an offer to connect. Alternatively, under the rules discussed above, a distributor may be trespassing or illegally using someone else's property to make a connection. If a distributor may deny connection if it requires the distributor to violate a law or license condition, than the distributor would not be obligated to connect a land-locked customer.

If a distributor refuses to connect a customer, there should be some protections afforded to a customer. In keeping with the spirit of the *Act*, it would be unacceptable to allow a distributor to walk away from its responsibility to service its licensed territory and provide a customer with no further ability to obtain connection.

Other requests for connection that require an expansion, reinforcement or upgrade require the distributor to make an offer to connect. Adopting this approach would grant consistency, but may not address the issue that is preventing connection unless a distributor is required to include an estimate of the cost to remedy the issue. Even then, a distributor may not be able to make an offer to connect because the reason for not connecting entails a remedy that the distributor is not able to provide. To protect both consumers and distributors, a distributor should be required to identify the reason for not making the connection and provide an estimate to remedy the issue whenever possible.

Recommendation

Options 2 and 6 were recommended.

The DSC will provide principles that a distributor must follow in determining whether it is obligated to make a connection. A distributor is not obligated to connect a building in its service territory if the connection would result in any of the following:

- Contravention of existing laws in Canada and the Province of Ontario.
- Violation of conditions in a distributor's licence.
- Use of a distribution system line for a purpose that it currently does not serve and that the distributor does not intend it to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor (i.e., the person requesting the service owes the distributor money).
- Any other conditions documented in the distributor's Condition of Service document that are consistent with the conditions identified above and with the goals delineated in the *Energy Competition Act, 1998*.
- If a distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor must inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

Voter Summary

Unanimous.

Dissenting Opinions

None.

2.4 CONNECTION AND SERVICE UPGRADE COSTS

[FINALIZED: MARCH 15, 2000]

Issue Statement

In making a connection, a distributor incurs costs. These costs may be charged to the customer or recovered through general distribution rates. The issues are:

> How is work related to a new service connection or a service upgrade classified or defined?
>
> Subsequently, how will the distributor recover the costs related to this work?

Options

1. The DSC will not prescribe any specific requirements regarding connection work.

2. The DSC will prescribe a uniform approach regarding connection work that must be followed by all distributors. The prescribed requirements would address the following:

   - What assets must be defined as connection facilities?
   - How must distributors treat connection work?
   - What approach must distributors use for recovering costs associated with connection work?

3. The DSC will be somewhat prescriptive by prescribing a uniform approach for some aspects of connection work while allowing distributors flexibility in other aspects.

Background Information

The process for dealing with Connections or Service Upgrades may involve one or more of the following:

(a) Expansion of the distributor’s distribution system on street allowance until it meets the closest point of supply that “lies along” the customer’s property.

(b) Work required to connect the new customer to the distributor’s distribution system from the street allowance to the “demarcation point.”

(c) Work required or facilities installed beyond the “demarcation point.”

(d) Residential subdivisions, at the point of offering to connect, are treated as "Commercial activity."

Work defined in (a) is classified as either "Expansion" and/or "Enhancement" of the distributor's distribution system. The associated cost recovery is addressed in a separate companion Economics summary of recommendation and is recovered via a combination of customer capital contribution and through tariffs.

Work described in (b) is defined as Connection Work.

Work outlined in (c) is the customer's responsibility and is in addition to "Connection or Service Upgrade Costs." Facilities in this category are owned and maintained by the customer and hence, do not form part of the distributor's assets.

A distributor's Conditions of Service should clearly define demarcation point, connection facilities and what is meant by "lies along." These definitions provide the basis for determining the proper allocation of costs.

Today, there is considerable variation in the way distributors treat connection costs. Some distributors include connection costs as part of a distribution tariff while others charge a separate connection fee. Some distributors include connection costs for some classes of customer (e.g., residential) in their tariff, but choose to collect connection fees to recover connection costs from other classes of customer (e.g., industrial/commercial).

Some distributors treat permanently-metered services differently from temporary services or Flat Rate (Unmetered) permanents.

Among those distributors that do charge a connection fee, there are varying practices. Some distributors charge a predefined fixed connection fee depending on type of customer and /or the required service size (e.g., commercial 600 amp Service), while others charge for each specific connection based on actual material and labor costs, again depending on the service size and class.

Various aspects of connection work are treated differently by different distributors, as discussed below:

- ***Distribution transformer:***

  - Sometimes included as part of distribution tariff and sometimes included as connection cost. This could depend on customer class. For example, residential may be in tariff; commercial/industrial could be either tariff or connection fee; and depending on the size of transformation, included in tariff (e.g., < 500 kVA) or paid by the customer (e.g., > 500 kVA).

– Sometimes capital contributions paid by a dustomer for distribution transformation capacity are considered associated with connection; sometimes they are considered associated with the distribution system (i.e., in the expansion category).

– Sometimes customers provide their own distribution transformation capacity and the distributor provides an allowance to the customer. This allowance may be considered under either connection or expansion.

- ***Overhead conductor or underground cable**:*

  – Usually considered part of connection work, at least up to a specified length (e.g., 6 meters for Underground and 30 meters for Overhead – no charge or fixed charge). The allowable length will depend on the chosen demarcation point.

  – Sometimes a customer is responsible for civil costs, such as trenching, if these are not considered part of standard connection work.

- ***Switch and fuse and other associated isolating or switching devices**:*

  – Sometimes considered as part of connection work (customer's contributions or actuals); sometimes considered as part of distribution system work (expansions).

- ***Metering**:*

  – Sometimes considered as part of connection work; sometimes considered as part of distribution system work (expansions).

- ***Additional pole or facilities in supply path to Customer**:*

  – Usually not considered part of connection work and usually requires a capital contribution.

- ***Pole replacement on main line to accommodate distribution transformer or customer tap**:*

  – Usually considered part of distribution system work (dealt with in expansions).

- ***Extension of secondary bus**:*

  – Usually considered part of distribution system work (dealt with in expansions).

- ***Design and inspection services**:*

  – Usually considered part of the Distributor's rate base and hence no charge. Others charge for this service as part of the connection fee.

Implementation Issues

- Proper unbundling and development of distribution tariffs.
- Determination of connection fees.
- Ownership and contestability.

Summary of Discussion

From a review of the various connection elements, it was felt that connection facilities should be defined to include secondary conductor or cable (excluding secondary bus or equivalent) and/or primary conductor or cable from the distribution system to the demarcation point with the customer. Connection facilities also would include associated supports or civil trenching, ducts and conduits. In addition to the actual facilities associated with a connection, it was felt that a connection should be defined to include services (e.g., service layout) associated with providing for the connection. In addition, it was felt that connection facilities should be further subdivided into Basic Connection Facilities and Variable Connection Facilities. Basic Connection Facilities would include the above services and provision of overhead line or underground cable up to a predefined length (e.g., 30 metres overhead or 6 metres underground). Requirements above and beyond these basic allowances would be considered as Variable Connection Facilities. All other facilities (distribution transformer, switches, fuses, isolating devices, metering) and services (design & inspection) would be considered part of the main distribution system and covered by compensation for expansions.

With regard to the question of how distributors should recover the costs associated with a connection, there are several different approaches discussed below. It was generally felt that the cost associated with the Variable Connection Facilities for requirements above and beyond the basic allowance should be recovered directly from the customer by way of a capital contribution. Recovery of costs associated with the Basic Connection Facilities could be recovered in one of the following ways, possibly differing by customer class.

1. Distributors could recover Basic Connection Costs through a separate Fixed Connection Fee. This Connection Fee would be determined (for each customer class) as the average cost of providing Basic Connection Facilities for all connections over a given period of time (e.g., annually). A further breakdown within each class (e.g., by service size) also could be considered. All customer connections for each customer class (or sub-class) would be charged this fixed connection fee.

2. Distributors could recover their Basic Connection Costs based on actual material and labour costs associated with each individual connection. In this scenario, a customer

would be charged for Basic Connection Facilities on the basis of actual work order costs associated with that specific connection.

3. Distributors could recover Basic Connection Costs as part of their distribution tariff. In this case, the distributor would accumulate all costs associated with providing Basic Connection Facilities in a separate account and include this account in their rate base for determining distribution tariffs.

Choosing to include Basic Connection Costs within distribution tariffs (as opposed to charging a connection fee) would have the following advantages:

- Connection assets become part of distributor's equity upon which a rate of return can be earned.
- Customers are not faced with a large up-front connection charge. This would likely be most critical for the residential customer class.
- There is little variation in actual standard connection costs from one customer to the next and cross subsidization is not a major issue.

Choosing to charge for Basic Connection Costs through a connection fee or based on actual material and labor has the following advantages:

- The distributor has lower distribution tariffs since connection costs are not included in the rate base.
- Including connection costs in a separate category aids contestability by peeling off some work from the monopoly distributor.
- Avoids risk of losing recovery on capital investment if customer leaves since connection fee would already have been paid.
- The distributor could earn a potential rate of return on Basic Connection Costs if the OEB were to rule that charging a connection fee to recover these costs is equivalent to recovery through a tariff.

If Basic Connection Costs are to be recovered through a connection fee, a *standard predefined fee* would be more easily applied by distributors, and more easily understood by customers.

Use of an average connection fee, however, may become problematic for the distributor if/when contestability becomes more of an issue. Using such an approach, distributors risk being saddled with the connections that are more costly than average while other contractors walk away with the connections that are less costly than average. Pricing each connection uniquely avoids any possibility of cross subsidization, but may be more difficult for a distributor to manage and more difficult for customers to understand.

The following are the main objectives to be achieved by the recommendation put forth in this summary of recommendation:

- The scope of connection work should be clearly defined for each class of service and standardized for all distributors.
- Cross-subsidization between existing and new customers and between different new customers should be minimized.
- Costs associated with connection work should be dealt with in a separate category distinguishing them from other distribution system costs.
- The treatment of connection costs should be standardized among all distributors as much as possible to reflect a uniform allocation between Basic Connection Costs and Variable Connection Costs.
- The method of recovering Basic Connection Costs (e.g., connection fee, tariff or actual material and labor) should be standardized among all distributors as much as possible.

Recommendation

Option 3 is recommended. All distributors shall have a mandatory, uniform approach towards connection work for Residential Class Customers. distributors shall have flexibility in their approach towards other Classes of Customers, guided by consistent treatment as described in their "Conditions of Service" document.

As part of Option 3, the following is recommended:

1. Distributors must define an Ownership Demarcation Point for each Customer Class and document this in their Conditions of Service.
2. A distributor's "Connection Assets" are defined as assets between the point of connection on the Distributor's distribution system and the Ownership demarcation point. These assets should not be included in the Distributor's Rate Allocation Study.
3. Costs associated with the installation of the Distributor's Connection Assets are recovered via a "Basic Connection Cost" and "Variable Connection Costs," as applicable.
4. Basic Connection Costs are costs associated with a "Standard or Normal" supply defined for each Customer Class by a distributor in the Conditions of Service. This Basic Connection may be referred to as a Standard Allowance. Variable Connection Costs are

costs associated with the installation of assets above and beyond the Standard Allowance.

5. For Residential Class Customers, distributors must define the Standard Allowance to include up to 30m of Overhead Conductor, or the equivalent credit for Underground Services. This Standard Allowance is recovered through the Distributor's Tariffs or Rates. Note also, for Residential Class Customers, the distribution transformer (in accordance with local design standards regarding overhead and underground supply practices) and any associated secondary bus is considered part of the distributor's main distribution system as opposed to Connection Assets. Incremental costs associated with the provision of non-standard distribution transformer requirements should be considered part of the Variable Connection Costs.

Voter Summary

Unanimous.

Dissenting Opinions

None.

2.5 THE NEED FOR SEPARATE POINTS OF DEMARCATION FOR OWNERSHIP VERSUS OPERATION

[FINALIZED: SEPTEMBER 15, 1999]

Issue Statement

It is important to define the point of demarcation between distributors and customers in order to define the obligations each has to the other. The point of demarcation also plays a role in determining who responsible for maintenance and repairs, what is recoverable through distribution rates and what rights a distributor has with respect to accessing equipment during an emergency. It is likely that the appropriate point of demarcation will differ by customer type. However, within a given customer type, different activities may warrant a different point of demarcation. In particular, there may be a need to have a different point of demarcation for ownership versus operation. The issue is:

> Should the point of demarcation between a distributor and its customer be different for purposes of ownership versus operation?

Options

1. There is <u>one</u> defined point of demarcation for each customer type.

2. The point of demarcation for the purposes of operation <u>may</u> differ from the ownership point of demarcation for a customer type.

3. The point of demarcation <u>must</u> be different for ownership versus operation.

Background Information

Distributors in Ontario have defined where their obligations end and a customer's obligations begin; these definitions differ by distributor. Great Lakes Power defines its point of demarcation as the customer's property line; customers own the feeder line from the property line to the building and are responsible for repair and maintenance of that equipment. Other distributors define their points of demarcation as being the point of connection to a building, the meter base, the top of the stack or at a protection device. Yet others have different definitions based on operation agreements they have with customers.

A distributor's point of demarcation also may vary by customer types. Larger customers with high voltages tend to own more distribution equipment than residential customers. However, distributors may be allowed access to equipment on the large customer's property during emergency situations.

Historically, a distributor's rate base has been determined by the point of demarcation. If a distributor owned a customer's feeder line inside a customer's property line, the distributor was responsible for maintenance and repair of this line and collected revenue for the cost of these activities through its rates. Customers would not be charged for these activities, but could be responsible for repairing any parts of their property that were adversely affected by the repair (e.g., a torn-up driveway or a garden that was dug up).

Existing customers are familiar with how their distributor has defined the point of demarcation. Going forward, it may be prudent to define a single point of demarcation for different customer types that would apply to all distributors across the province. This would standardize ownership of equipment and create a consistent definition for purposes of adjusting distribution rates. If a consistent point of demarcation is to be applied to the province, it will be even more important to decide whether the same definition should be applied for ownership and operation reasons.

Implementation Issues

Given that the point of demarcation differs by distributor, and has been incorporated into each distributor's rates, changing the point of demarcation for existing customers may be equivalent to requiring divestiture of assets, an act that the Ontario Energy Board (OEB) is prohibited from doing under section 128 of the *Ontario Energy Board Act, 1998*. However, going forward, a consistent point of demarcation for new customers does not appear to create this problem. Thus, there could be a phase-in if a single definition for the point of demarcation is required. Existing customers would continue to be serviced under the old definition. As they moved or were replaced with new accounts, the new accounts would be established with the new point of demarcation defined as required under the single definition.

Summary of Discussion

It is easy to think of a single point of demarcation between a distributor and a customer for all purposes. A single definition is simpler and consistent. However, there may be instances where the point of demarcation for ownership may not allow the safe and reliable operation of the distribution system. For example, if the point of demarcation for ownership is the property line, and the property line has not protection device or cut-off point, a distributor may be required to use a piece of equipment inside the customer's property line to isolate emergencies and secure the reliability of the distribution system. In this example, the point of demarcation for operational reasons could be the protection device.

There may be good reasons to have different points of demarcation for ownership versus operation. Potential definitions of the points of demarcation for each purpose would be discussed separately. If these discussions result in different definitions, there does not appear to be a compelling reason to modify the recommendations to make them the same. However, if they define the point of demarcation as the same for ownership and operation for certain customers, there does not appear to be any reason to require the definitions to differ.

Recommendation

Option 2 is recommended. The point of demarcation for the purposes of operation may differ from the ownership point of demarcation. The appropriate point of demarcation for ownership versus operation should be dealt with separately and reported in separate recommendations.

Voter Summary

Unanimous.

Dissenting Opinions

None.

2.6 POINT OF OPERATIONAL DEMARCATION FOR SERVICE CONNECTION

[FINALIZED: SEPTEMBER 1, 1999]

Issue Statement

When defining service for connections or expansions, some bounds must be set to establish a point of where the obligations of the customer end and those of the distributor begin. There appears to be a need to separate ?Operational Control? from ?Ownership? issues in order to deal with safety related situations. The issue is:

> What is the ?Operational Point of Demarcation? or boundary for purposes of system operation, isolation, and safety responsibilities?

NOTE: The Ownership Demarcation Point will be discussed under a separate Summary of Recommendation

Options

1. Allow each distributor to set its own Operational Point of Demarcation.

2. Provide a general description of Operational Point of Demarcation that can be similarly interpreted and applied by all distributors in their local operational practices and Conditions of Service documents. These definitions would be separate for each customer type and may be further defined in an ?Operating Agreement? between the distributor and the customer.

3. Provide a prescriptive definition of Operational Point of Demarcation that does not allow any variance by the distributor with regard to where this boundary is set.

Background Information

Survey information collected from distributors represented on the Distribution Supply Code Task Force indicates that each distributor generally has defined an Operational Point of Demarcation based on local situations and reasons. For instance, for residential customers with overhead services, this point often is the top of the service stack on the home because this is the first point of connection beyond the pole on the street; in other areas, the operational point of demarcation is the first disconnect device on the customer's property. Other distributors have adopted the property line as the point of operational demarcation to be consistent with other municipal utilities such as water and sewers.

Operationally, distributors need to have some means of control over a disconnect device on, or at the customer's property for the purposes of electrical isolation, interruption of service for various reasons, and to maintain control over the system as a whole for the purpose of delivering electricity.

Implementation Issues

Option 1: Allowing each distributor to set the Operational Point of Demarcation individually would allow too much variability across the province and would force the OEB to review this information annually with the rates submission.

Also it would not allow the customer to have the benefit of some level of consistency among distributors as they interact with them across the province.

Option 2: Providing a general description of Operational Point of Demarcation would be consistent with the DSC**?**s position of many other issues relating to Service and Connections. The general description allows the distributor to apply the definition to suit the distributor's Conditions of Service. However, too broad a definition would allow a wide variety of interpretations.

Option 3: Creating a single definition for the Operational Point of Demarcation for all services will ensure consistency across the province and impose little additional regulatory burden on the OEB. A customer looking for a service connection anywhere across the province would always have the same Operational Point of Demarcation.

Summary of Discussion

A couple of draft positions were tabled for discussion. These are:

The <u>Operational Point of Demarcation</u> for an electrical service shall be an isolation point or device located on or adjacent to the customer property that is deemed by the distributor to be critical for insuring employee work protection and public safety.

A distributor shall be granted *Operating Control* of an electrical service up to and including the Operational Point of Demarcation.

The distributor may select the first isolation device on the property in most cases, but there may be some instances where another point might be selected for reasons of safety or ease of access under emergency conditions.

The distributor should define this point of operational demarcation by customer type in the distributor's Conditions of Service. For large customers, it might be better to define these point(s) in an Operating and Maintenance Agreement which outlines the responsibilities of each party with respect to the facilities concerned.

Operating Control shall mean the right to direct and control the use of and operation of an electrical device for the purpose of providing isolation for work protection, but will not imply ownership for repair or maintenance purposes.

Recommendation

Option 2 is recommended. A general definition for Operating Point of Demarcation should be developed and adopted into the DSC. The term "Operating Control" also should be defined.

Within the guidelines provided in the DSC, a distributor shall establish an Operational Point of Demarcation by Customer Class and clearly state these boundaries in the distributor's Conditions of Service.

Voter Summary

Unanimous.

Dissenting Opinion

None.

2.7 POINT OF OWNERSHIP DEMARCATION FOR SERVICE CONNECTION

[FINALIZED: MARCH 20, 2000]

Issue Statement

When defining service for connections or expansions, some bounds must be set to establish a point of where the obligations of the customer end and those of the distributor begin. There appears to be a need to separate "Operational Control" from "Ownership" issues in order to deal with safety related situations. The issue is:

> What is the "Point of Ownership Demarcation" or boundary between a distributor and a customer for the purposes of financial transactions, maintenance, and repair responsibilities for the life of the service?

The recommendation will have to address any pre-existing boundaries that a distributor may have established, as well as what should be done going forward from the time the DSC is adopted.

Discussions related to connections of new residential subdivisions and contributed capital for connections are dealt with as separate subgroup topics and have not been dealt with in this Summary of Recommendation.

Options

1. Allow each distributor to have the complete freedom to set their own Point of Ownership Demarcation for any customer based on whatever criteria they choose and allow this point to be different for each customer.

2. Each distributor would be required to establish this boundary for each customer type and publish this information in the distributor's Conditions of Service. This information would be required to be submitted to the OEB with the annual rates submission and any changes in policy would have to be communicated to the OEB.

3. Require that each distributor establish a boundary, as in Option 2, but layout a phased move to a very prescriptive definition that does not allow any variance by the distributor with regard to where this boundary is set.

4. Establish a very prescriptive definition that does not allow any variance by the distributor, to be implemented immediately upon the adoption of the DSC.

Background Information

Survey information collected from over 150 distributors indicates that each distributor has defined a Point of Demarcation based on local situations and reasons. There are very common points established for certain classes and types of service. For instance, for residential customers with overhead services, this point is most often the top of the service stack on the home because this is the first point of connection beyond the pole on the street. While in some areas, the point of demarcation is the property line to be consistent with other municipal utilities such as water and sewers. Bell, Cable, and Gas are presently taking responsibility of all plant closer to the home, however, Bell has recently drawn back to the main panel instead of right to the service jack for new installations.

The survey results showed that in the residential class, a high degree of consistency of demarcation points exists and that in the larger general service class, a much wider variance is evident.

Implementation Issues

When evaluating each of the options, the six objectives of the OEB were considered. The lists of Pros and Cons for each option were developed with these criteria in mind. The objectives of the OEB are (taken from the *Ontario Energy Board Act, 1998*):

1. To facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition.

2. To provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario.

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

4. To promote economic efficiency in the generation, transmission and distribution of electricity.

5. To facilitate the maintenance of a financially viable electricity industry.

6. To facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources in a manner consistent with the policies of the Government of Ontario.

Summary of Discussion

Each option was evaluated in light of the goals of the OEB.

Option 1: Allow each distributor to have the complete freedom to set their own Point of Ownership Demarcation for any customer based on whatever criteria they choose and allow this point to be different for each customer,

Pros	Cons
Allows the most freedom **for a distributor** to subsidize or attract one type of customer by affecting connection costs.	Would result in a very large regulatory burden on the OEB to manage and police to ensure the customer is not be discriminated against for whatever reason.
Would promote competition between distributors for new "desirable"customers.	Would not sufficiently protect the customer from potential price gouging by a distributor.
The distributor is not likely to make significant changes for existing customers because of large amounts of work to adjust the asset base, and the fact that most of the existing services will not meet the Electrical Safety Code. This will result in a minimal amount of change for the customer.	Would discourage competition for the "less desirable" customers.
	Would result in no consistency for the customer when comparing offerings from different distributors.

Option 2: Each distributor would be required to establish an ownership boundary for each customer type and publish this information in the Conditions of Service document.

Pros	Cons
Most distributors are likely to carry on with the present points of demarcation resulting in the least amount of change for existing customers.	Might be seen as the distributors trying to maintain the "Status Quo". The OEB may not agree with this approach as it might not be conducive to improved efficiencies and competitive rates.

Pros	Cons
Would result in the least amount of additional costs for the distributor. A mandated change in demarcation point would impact on asset base for rate calculations, adjustment of accounting procedures, etc. These additional “transition” charges likely would increase distribution rates to the customer	Regulatory burden is increased compared to the prescriptive approach due to the need to evaluate these asset changes.
Consistent with the direction of other Summary of Recommendations coming out of the DSC groups to date.	Increased regulatory burden on the distributor.
Once established, the demarcation point for a distributor is unlikely to change often because of the reporting and justification required by the OEB to allow the change.	From a contractor's point of view this is better due to the standardized equipment and practices.
Protects the customer from cross subsidizing between customer types because the rules are set in the Conditions of Service.	
Would allow the distributor to maintain the same point for Ownership and Operating purposes if they currently do so. Would cause less confusion for the customer and avoid the need to change existing Operating and Maintenance Agreements.	
The OEB would see less regulatory burden than option 1, but it would be required to review this information annually.	
Would ensure some level of consistency for customers when comparing offerings from distributors in that the Conditions of Service document will provide a standard format for the information.	

Option 3: Require that each distributor establish a boundary as in Option 2, but layout a phased move to a very prescriptive definition that does not allow any variance by the distributor with regard to where this boundary is set. The pros and cons for each mandated point of demarcation would be developed in a separate Summary of Recommendation.

Pros	Cons
Going forward, it establishes a clear point of demarcation that is consistent across all distributors across the Province. It does nothing to address existing services and demarcation points.	Distributor will have a difficult time keeping track of which customer has what demarcation point. Added costs of information and record keeping would impact on distribution rate.
Ultimately it minimizes the amount of OEB regulatory burden with respect to this issue, freeing time for other regulatory issues.	Customers may be confused about the difference in treatment between existing and new customers.
A consistent boundary across the Province would allow this to be referred to in legal documents pertaining to property ownership and transfers through sales. Once this is solidly established, it would ensure ongoing consistency driven by legal needs.	Would require a change in design philosophy for some distributors that are not already in-line with the new mandated boundary. This could result in added costs to the distributor that would be reflected in the rates.
Less regulatory burden on both OEB and distributors.	Transition problem for the customer (new vs existing) and might be seen as subsidization of one customer by another.
Harmonizes other issues such as contributed capital.	
Consistency from the electrical contractors point of view.	
Consistent for the distributor.	

Option 4: Establish a very prescriptive definition that applies to all connections (new and existing) and does not allow any variance by the distributor. To be implemented immediately upon the adoption of the DSC.

Pros	Cons
Eliminates the confusion for the distributor with regard to which boundary applies to each service.	This would force some distributors to divest (or invest) assets to meet the new point of ownership rules. The OEB may not have the authority to order such divestment.
Eliminates the confusion over ownership for the customer.	Most of the existing plant that would be divested does not meet the Electrical Safety Code for Ontario.

Pros	Cons
	Puts more burden on the customer for repairs for plant, the installation of which, they were not involved with or responsible.

If the group recommendation is to select Option 3 or 4, then another Summary of Recommendation should be started to address the pros and cons of each potential point of demarcation.

There was a concern that any hard and fast Province-wide standard would create winners and losers among distributors and that the disruption of existing practices seemed to outweigh any possible benefit of standardization.

It was felt that as amalgamations occur, distributor variances in demarcation points naturally would decline and best practices would be chosen based on local experience. This was seen to be superior to a predetermined, prescribed demarcation point.

The question of contestability of installation and maintenance of the service infrastructure was discussed. The issue is that contractors possibly would be blocked out of the market of providing services as a result of distributors defining demarcation points further downstream on the system. It was felt that distributors historically have had neither incentive nor disincentive on the issue of contestability of provision of serviceand distributor's current demarcation points have been arrived at through determination of suitability in reference to reliability issues and ease of maintenance and administration.

Fair and equitable treatment of customers was discussed as one of the main goals in formulating a recommendation. Province-wide standardization was not seen as essential to this goal in that any variances that do exist now would be insignificant as far as customers choice of location. Local fair and equitable treatment was seen as a more important goal to attain.

The Electrical Safety Authority (ESA) recently announced that it would like to review, in consultation with distributors, their current practices and procedures in relation to their exemptions from the Ontario Electrical Code. This may have a bearing on where the logical demarcation point should be established. The prescription of a standard demarcation point would be best left until after ESA’s review.

Recommendation

Option 2 was recommended. Each distributor should be required to establish a point of Ownership Demarcation for each customer type and publish this information in its Conditions of

Service document. This information would be required to be submitted to the OEB with the annual rates submission and any changes in existing policy would have to be communicated to the Board.

This situation should remain in effect for a time that is consistent with the lifetime of the First Generation PBR scheme, and should be reviewed by the OEB again at that time.

Voter Summary

Unanimous.

Dissenting Opinion

None.

2.8 CONNECTION SERVICE AGREEMENT

[FINALIZED: MARCH 20, 2000]

Issue Statement

The issue is:

> Should a distributor be required to have a Connection Agreement in place with each of its customers?

Options

1. **Minimalist Approach:** The DSC would be silent on the requirement of a Connection Service Agreement and allow each distributor to make a decision.

2. **Modified Prescriptive Approach:** The DSC would specify that a Connection Service Agreement for certain customers is required and would specify what should be covered in the Agreement. A template would be provided which a distributor could choose to follow.

3. **Prescriptive Approach:** The DSC would specify that a Connection Service Agreement for certain customers is required and would specify the content and form of the Agreement.

Background Information

Most distributors already have some sort of Connection Agreement with their larger customers. In some cases this includes operating instructions specific to the customer. In the past, under the Standard Application of Rates (SAR) there was an implied contract with the customer based on the delivery of service. It is expected that under the Retail Settlement Code (RSC), an implied contract will continue for customers where no signed agreement exists.

Summary of Discussion

The group felt that the purpose of a Connection Agreement was to inform customers of their rights and responsibilities and to protect the distributor. It is to cover the ongoing relationship with the customer, not the arrangements for service connection. It was felt that there definitely was a need for a Connection Agreement for all Embedded Generators because of the higher level of complexity of the connection. For similar reasons, it was felt that there should be agreements in place with embedded wholesale market participants.

Although the group felt that it was important for a distributor to have a signed agreement with larger customers, there seemed no need to make them mandatory. There will be varying degrees of administrative complexity in obtaining agreements with existing customers. It was felt that the distributor would be in the best position to establish its criteria for selecting what size/class of customer requires a connection service agreement.

The introduction of new regulations and license requirements may change the past behaviors and expectations of both customers and distributors. The group felt that the end-state situation would be that most non-residential customers that have any kind special features of their service most likely would be captured within a connection service agreement.

Recommendation

Option 2, the modified prescriptive approach, is recommended. The DSC will require a distributor must have a Connection Agreement with all embedded generators and wholesale market participants connected to its system within its service territory. Further that a distributor may choose to have a Connection Agreement with some or all of its load customers. The DSC should state what terms and conditions must be covered by the Embedded Generator Connection Service Agreement and a template should be provided for a Connection Agreement for load customers.

Voter Summary

Unanimous.

Dissenting Opinion

None.

Attached:	Appendix 1:	Connection Agreement Template
	Appendix 2:	Mandatory Terms of a Connection Agreement with Embedded Generators

APPENDIX 1
Connection Agreement Template

A Connection Agreement should include the following information:
(Note: examples of what to include are provided in *italics*)

Date
Account Number
Date Customer's Responsibility Commences
Name
Service Address
Mailing Address
Home Phone No
Business Phone No
Type of Business
SIC

The Customer agrees to abide by the Distributor's Rules, Regulations and Conditions of Service, in effect and as amended from time to time.

The Customer further agrees to:

(1) pay the Distributor for the electrical energy consumed by the customer at the location covered by this agreement from the date herein until such time as the customer no longer requires the service, and
(2) (2) to commence payment on or before the due date shown on the first account rendered and to pay all accounts either monthly or bi-monthly according to the class rating of the service for such energy and service in accordance with the applicable rates.

Signature of Customer (after reading the above and the General Conditions)
Witness
Signature of Distributor (upon accepting the contract)
Date

General Conditions:

Space and Access
For example: *The customer agrees to provide suitable space for the Distributor's meters, wires and where necessary poles, cables, transformers and all other appliances and equipment on the said premises and further agrees that no one who is not an agent of the Distributor shall be permitted to remove, inspect or tamper with same, including seals and that the properly authorized agents of the Distributor shall at all hours have free access to the said premises for*

the purpose of reading, examining, preparing or removing their meters, wires, poles, cables, transformers and other appliances and equipment of the Distributor and for the inspection of all the customer's appliances and wiring.

Responsibility for Equipment
For example: *Meters, wires, poles, cables, transformers and all other appliances and equipment of the Commission on the said premises shall be in the care and at the risk of the customer and if destroyed or damaged by fire or any other cause whatsoever other than ordinary wear and tear, the customer shall pay to the Distributor the value of such meters, wires, poles, cables, transformers, appliances and equipment, or the cost of repairing or replacing same.*

Disconnection
For example: *The customer hereby expressly authorizes and empowers the Distributor as its option to remove the meter, wires, poles, cables, transformers and all other appliances and equipment installed at its expense and discontinue the supply of electricity and terminate this agreement whenever any bills for the said service are in arrears or upon violation by the customer of any of the terms and conditions of this agreement.*

Reliability
For example: *The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted service but does not guarantee a constant service or the maintenance of unvaried frequency of voltage and will not be liable in damages to the customer by reason of any failure in respect thereof. It is the customer's responsibility to provide under or over voltage protection devices for the protection of his equipment.*

Conditions of Service
For example: *The building must be supplied with electrical energy according to the Distributor's Conditions of Service.*

Binding
For example: *This agreement shall not be binding upon the Distributor until accepted by it through its proper officers and shall not be modified or affected by any promise, agreement or representation by any agent or employee of the Distributor unless incorporated in writing into this agreement before such acceptance.*

Charges
For example: *The customer agrees to pay the Distributor charges for plant as determined based on the Conditions of Service and the Distributor's approved rates. The customer shall maintain the installation in efficient condition with proper devices, according to the requirements and rules of the Electrical Safety Authority (ESA). If the electrical installation is found to be inadequate, the supply of electricity shall be suspended until such time as the above requirements are in compliance.*

Security Deposit
For example: *The Distributor reserves the right to require security for payment of future charges.*

Termination
For example: *This agreement shall continue in force until terminated by notice in writing given by either party hereto thirty days in advance of termination.*

Successors
For example: *It is agreed that the signatures of the parties hereto shall be binding upon their successors or assigns and that the vacating of the premises herein named shall not release the customer from this agreement except at the option and by written consent of the Distributor.*

Approval of Equipment and Power Factor
For example: *All electrical and mechanical equipment used by the customer shall be subject to the reasonable approval of the Distributor and the customer shall so take and use the electrical energy as not to endanger the apparatus of the Distributor or cause any wide or abnormal fluctuations of its line voltage. All motors shall be selected with reference to secure the highest feasible power factor at loads. Where practical, equipment with the highest power factor should be chosen and motors be sized to match the load. The Distributor shall check power factors and when found to be below 90%, reserves the right to install a kVA meter and bill on the kW or 90% of the kVA, whichever is higher. This constitutes a penalty for power factors below 90%. Motor starting current shall be subject to approval of the Engineering Department and in accordance with the Distributor's Conditions of Service.*

Theft of Power
For example: *Whenever the Distributor shall find that on the customer's premises more electricity is used than is being paid for to the Distributor, it may charge for such excess at tariff rates from the date of the contract or the date of the last inspection on said premises. If there is a meter and devices have been installed in such manner as not to register on said meter, the Distributor may charge the customer for such usage based on estimated consumption of electricity for all load not registering on the meter. If intent to defraud in indicated, criminal charges may be laid.*

Meter Problems
For example: *If a meter ceases to register or has registered incorrectly, the customer shall pay for the energy supplied a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises, due regard being given to any change in the character of the installation and on the demand.*

Fire or Other Casualty

For example: *In case fire or other casualty shall occur in said premises, rendering them wholly unfit for occupancy, the supply of electricity shall thereupon be suspended until such time, within said contract period, as the wiring shall have been repaired and approved by the ESA.*

APPENDIX 2
Mandatory Terms of a Connection Agreement

Each Connection Agreement with an Embedded Generator shall contain specific terms and conditions relating to connection and access to the distribution system. Such terms and conditions include, but are not limited to, the following:

1. Requirements for the inspection and testing of equipment
2. Requirements for maintenance of the equipment.
3. Worker protection and safety considerations, and measures to protect the public and the environment.
4. Requirements for testing protection systems associated with the connection.
5. Requirements for reporting any change affecting connected equipment of the configuration of this equipment
6. Protocols for the provision of load forecast or forecasts of information
7. Terms and conditions for disconnection and reconnection, including as to the responsibility for the payment of costs associated with reconnection
8. Requirements for coordinating maintenance and operations.
9. Duration and termination conditions
10. Details of the connection point, including the ownership of the facility
11. Connection service charges and payment conditions
12. Requirements for reporting changes affecting access to metering, monitoring and telemetry equipment
13. Circumstances that would require re-negotiation of the Connection Agreement.
14. Information requirements exchange procedures.
15. Communication and operating protocols between distributor and generator for routine day-to day operating matters and under emergency conditions.
16. Access to connection facilities.
17. Assignment of Controlling Authority

2.9 ENHANCEMENT EVALUATION MODEL

[FINALIZED: MARCH 20, 2000]

Issue Statement

Currently, distributors perform enhancements as part of the maintenance and operation of distribution systems. Internal financial evaluations of various magnitudes and methodologies are carried out today and are considered a normal business function of all existing distribution utilities. The issue is not that a new practice should be introduced due to changes in the way the industry is being regulated, but rather that due to those changes, distributors will be carrying out evaluations in a system with quite different financial drivers.

The issue is:

> To what degree should the DSC prescribe financial evaluation criteria for projects that are to be funded by a distributor and do not require external investment through capital contribution by others?

One of the primary considerations in developing the recommendation is establishing the level of distributor autonomy that is deemed to be in concert with the tenets of performance based regulation. Those tenets being continuous improvement in performance and a focus on results as opposed to activities.

Options

1. A model similar to the one in the economic evaluation recommendation should be prescribed. The cost inputs and matching revenues of a project would be weighed against the costs and revenues associated with maintaining the status quo plus any lost revenue or penalty associated with not meeting relevant performance targets. Projects would have to show a positive outcome before a distributor could initiate. Records would be kept on hand for potential regulatory audit purposes.

2. The DSC should include suggested criteria and principals for distributors to evaluate enhancement projects, recognizing what would be prudent investment in a generic sense. Distributors would be expected to follow as a measure of due diligence.

3. The DSC should include statements of expectation of the distributor to use rational, self developed evaluation methodologies, that are intended to be in concert with the end goals of performance based regulatory philosophies.

The DSC should remain silent on the issue and allow each distributor to make business decisions related to enhancements in accordance with the incentives of PBR and conditions of licence.

Summary of Discussion

A companion document, Summary of Recommendation (SOR) on economic evaluation, addresses expansion evaluations where a party other than the distributor may be asked to contribute to the cost of the project. There also may be situations where the costs of two proposed expansions to meet the same need may have to be compared so as to ascertain which of the two best meets the criteria of rational, cost effective distribution system expansion.

The importance of having a uniform and transparent evaluation methodology for expansions that fall into the aforementioned examples is fully documented in the SOR on economic evaluations. As a way of bridging the two companion SORs, it can be said that the economic evaluation model primarily deals with situations that have the potential to have a financial impact on someone other than the distributor, as in when a capital contribution is required from a customer. Where as, enhancement evaluations are done primarily to test the financial wisdom of a proposed activity where only the distributor is contributing, as is the case with a line replacement or a voltage conversion. (Refer to charts 1 and 2)

Internal financial evaluations of various magnitudes and methodologies are carried out today and are considered a normal business function of all existing distribution utilities. In the future, distributors will be carrying out evaluations in a system with quite different financial drivers. Changes to financial drivers include but are not limited to the following:

- The percentage of the volumetric portion of the cost of electricity that a distributor will receive as a revenue stream has been reduced.
- The socio-economic drivers, that many municipal utilities reacted to in the past by considering such things as local industrial productivity when preparing business cases for enhanced reliability projects, has taken a new form.
- Reliability and customer service performance benchmarking will eventually be key indicators for investment decisions.
- The required year over year productivity increases will maintain the pressure to only invest activities that add value for the shareholder.

One could argue that the financial evaluations of the past have always taken into account the same key drivers of reliability and customer service that the new performance based regulation focuses on and therefore little will change going forward. To the extent that this is true for each individual distributor will depend on how the individual distributor made its financial investment decisions in the past.

Much of the debate centered on the value records of internal investment evaluations may be to others, in a PBR regime. The contrasts of PBR and cost based treatment of spending activities and their association to rates was explored. In this context, it was agreed that the current reporting requirements of the gas distributors is based on a cost-based regulatory framework that is fundamentally different from the performance framework of the electrical distribution regulation.

Distributors have had their revenue streams established in accordance with their historic spending levels. Payments in lieu of taxes and fair market return aside, the monies the distributor is taking in now should, in theory, match the system reinvestment requirements as a starting point of going forward. With this in mind, additional cost of investment is not likely an appeal available to a distributor seeking an upward rate adjustment.

It stands to reason then, that the regulatory outfall is that the distributor can be self-policing in its investment decisions. Further to this, it would not be unreasonable to expect that a distributor will have the financial ability to sustain the system in such a way as to avoid long term deterioration with the current available revenue streams.

Rebasing of rates was discussed as a possibility in the 2nd generation of PBR. It was decided that this is a possibility that distributors may choose to consider in their investment decision-making activities. The uncertainty of this happening suggests that our recommendations should be neutral regardless of whether rebasing happens.

The Board's intent of choosing PBR oversight along with its associated results monitoring focus, seemed to be at odds with anything overly prescriptive in this particular area. Channeling distributor options along a predetermined strict evaluation path could stifle the natural evolution of best management practices that would occur if multiple distributors were left free to take calculated risks in a more entrepreneurial environment.

There was a stated concern for the short-term ability of the current PBR indices to properly incent distributors to make investment decisions that support the goal of continuous improvement in reliability and economic efficiency of electricity distribution. The PBR indices, as they stand now, cannot be used in isolation of other factors to support enhancement investments.

The group felt that if reasonable, prudent and experienced-based investment evaluations are to continue, a distributor should be allowed to utilize its own rational and triggers to justify their investment decisions internally.

The group felt that the 1st generation of PBR reliability indices, to some degree, will act as a transitional tool to establish benchmarking and will allow distributors time to establish processes to collect the data in more detailed fashion. It was felt that our recommendation could safely be based on an assumption that evolving indices could include momentary outage frequency and reliability per individual customer data.

The same concern of possible short-term investment strategy based on current PBR reliability indices in isolation was raised in the SOR dealing with preventative maintenance. The group felt that the recommendation to prescribe inspection activity levels adequately addressed the issue of the potential relaxation of maintenance activities due to the current PBR reliability indices.

Safety is an obvious component of any desired outfall of the emerging regulatory framework. The group felt that this issue is adequately addressed in other recommended inclusions to the DSC.

In general, it was felt that, as with most recommendations, a balance must be struck between prescribing activities, having projected the outcome of those prescriptions and allowing distributors to utilize their individual expertise to obtain stated desired outcomes. The hazard of prescription is that, in essence, the DSC could become a management manual that imposes homogenous methodologies throughout the province. This would negate the evolution of best management practices being identified from distributors exercising results driven entrepreneurial liberty.

The group discussed distributor investments in systems typically employed by distributors that assist in either the reliability enhancement or system capacity management. These two areas were seen as the two core requirements for distributors in relation to system enhancement. The systems identified were Geographic Information Systems (GIS), Supervisory Control & Data Acquisition (SCADA), and Automated Mapping & Facility Management (AM-FM).

It was felt that these investments, given the results based regulatory framework, were best left to distributor discretion in that the sole reason one would invest in such a system would be performance based.

There was some discussion on the pending regulation dealing with expansions under section 92 of the *Ontario Energy Board Act, 1998*. As with the SOR on economic evaluation, it was felt that any regulatory requirement dealing with section 92 would supersede a code requirement and therefore would not be addressed in the DSC.

Distributors have always had to make internal economic evaluations based on external drivers, balancing maintaining the distribution system versus enhancement through capital rebuild. It was felt that, although the economic drivers may change, the industry as a whole would be better served if the competitive nuance of the PBR framework is left unencumbered by DSC caveats on enhancement evaluations.

That being said, the group still felt it would be prudent to include principles in the DSC that a distributor would be expected to consider in an enhancement evaluation. In this way, the DSC can be utilized to reduce the risk of system deterioration in the early stages of the new PBR requirements.

Recommendation

Option 3 is recommended.

The DSC should include statements of expectation of the distributor to use rational, self-developed evaluation methodologies, that are intended to be in concert with the end goals of PBR philosophies.

Principles that distributors are expected to give consideration to in evaluating enhancements are as follows:

- Improvement of system to either obtain or maintain required performance based indices.
- Avoidance of deterioration of the distribution system.
- Current levels of customers service and reliability.
- Costs to customers associated with distribution reliability.
- That good utility practices be deployed including prudent planning for long-term reliability.

Voter Summary

Unanimous.

Dissenting Opinion

None.

Attached: Table 1: Project Evaluation Categories and Evaluation Emphasis
Table 2: Categorization of Distribution System Activities

Table 1:
Project Evaluation Categories and Evaluation Emphasis

Project Category	Evaluation Emphasis	
	System Enhancement Evaluation	**Economic Evaluation**
Projects to: _ Improve Reliability, Power Quality or asset life replacement _ Relieve Congestion due to system wide load growth	Primary due	Secondary
Projects to: _ Accommodate existing specific Customer Demands for Increased Capacity _ Connections e.g. new subdivision. _ Accommodate load growth due to new customers	Secondary	Primary

Categorizing of Activities

The following table breaks down various work activities by, reason for doing the work (Project Driver), activity definition (Expansion, Reinforcement etc.) and what customers benefit from the activity. The right hand column is a suggested primary evaluation treatment based on Table 1. The evaluation treatments are shown as:

a) Economic Eval (Eco Eval); and

b) Enhancement Evaluation (Enhance Eval).

It is understood that the following activities and associated drivers are seldom stand-alone as depicted. It is common to have these activities and project drivers occur as a hybrid of two or more of the initiatives. In the case of hydrids, the issue is one of unbundling costs and matching to the associated benefactors.

Many activities described here become routine by nature and can perhaps be identified an ongoing program. These programs may require a special evaluation treatment.

Table 2: Categorization of Distribution System Activities

	Project Driver	Activity Category	Who Benefits?	Evaluation Primary	Evaluation Secondary
1) Build Additional Feeder in Existing System Area	1. Load increase due to new customers 2. Load increase of existing customers 3. Reliability gains of loop feed options	1. System Expansion 2. System Expansion 3. System Expansion	1. New Customers 2. Existing Customers 3. Existing Customers	1. Eco Eval 2. Enhance Eval 3. Enhance Eval	Enhance Eval Eco Eval Eco Eval
2) Build Additional Feeder Outside of Existing System Area	1. Load increase due to new customers 2. Reliability gains of loop feed options	1. System Expansion 2. System Expansion	1. New Customers 2. Existing Customers	1. Eco Eval 2. Enhance Eval	Enhance Eval Eco Eval
3) Replacing Existing O/H Conductors with higher capacity conductors	1. Load increase due to new customers 2. Load increase due to existing customers 3. Reduce Losses 4. Meet current Standards 5. Life Cycle Replacement	1. Reinforce 2. Reinforce 3. Reinforce 4. Reinforce 5. Replacement	1. New Customers 2. Existing Customers 3. Existing 4. Existing 5. Existing	1. Eco Eval 2. Enhance Eval 3. Enhance Eval 4. Enhance Eval 5. Enhance Eval	Enhance Eval Eco Eval Eco Eval Eco Eval Eco Eval
4) Replacing Existing U/G Conductors with higher capacity conductors	1. Load increase due to new customers 2. Load increase due to existing customers 3. Reduce Losses 4. Meet Current standards 5. Life cycle Replacement	1. Reinforce 2. Reinforce 3. Reinforce 4. Reinforce 5. Replacement	1. New Customers 2. Existing Customers 3. Existing 4. Existing 5. Existing	1. Eco Eval 2. Enhance Eval 3. Enhance Eval 4. Enhance Eval 5. Enhance Eval	Enhance Eval Eco Eval Eco Eval Eco Eval Eco Eval
5) Converting to a higher Voltage on an early asset retirement schedule	1. Reduce losses 2. Reduce System Operating Costs 3. Lower real estate costs	1. Reinforce 2. Reinforce 3. Reinforce	1. Existing 2. Existing 3. Existing	1. Enhance Eval 2. Enhance Eval 3. Enhance Eval	Eco Eval Eco Eval Eco Eval

ACTIVITY	PROJECT DRIVER	Activity Category	Who Benefits?	Evaluation Primary Secondary
6) Installation of automatic switching devices	1. Decrease in outage time	1. Reinforce	1. Existing Customers	1. Enhance Eval Eco Eval
7) Installation of a transformer bank	1. Customer request for connection	1. Connection	1. New Customer	1. Eco Eval Enhance Eval
8) Installation of U/G Service	1. Customer request for connection	1. Connection	1. New Customer	1. Eco Eval Enhance Eval
9) Installation of 2 phases where 1 previously existed	1. Customer Request for connection 2. Increased load due to new customers 3. Increased load due to existing customers 4. Reliability gains due to loop feed options	1. Connection 2. Expansion 3. Expansion 4. Reinforce	1. New Customer 2. New Customers 3. Existing Customers 4. Existing Customers	1. Eco Eval Enhance Eval 2. Eco Eval Enhance Eval 3. Enhance Eval Eco Eval 4. Enhance Eval Eco Eval
10) Replacement of defective devices i.e. Insulators, (early asset retirement)	1. Decrease in outage time 2. Safety Concerns	1. Replace 2. Replace	1. Existing Customers 2. Existing Customers	1. Enhance Eval Eco Eval 2. Enhance Eval Eco Eval
11) Normal Life Cycle replacement of system components	1. Reliability 2. Meet current standards 3. Safety concerns	1. Replace 2. Replace 3. Replace	1. Existing Customers 2. Existing Customers 3. Existing	1. Enhance Eval Eco Eval 2. Enhance Eval Eco Eval 3. Enhance Eval Eco Eval
12) Installation of infrastructure for residential and industrial subdivisions	1. Developer wants inventory of serviced properties	1. Expansion	1. Developer	1. Eco Eval Enhance Eval

ACTIVITY	PROJECT DRIVER	Activity Category	Who Benefits?	Evaluation Primary	 Secondary
13) Site Specific reliability initiative to bring reliability up to standard	1. Performance Based Requirement 2. Customer complaint resolution	1. Reinforce	1. Existing Specific	1. Enhance Eval	Eco Eval
14) Site Specific reliability initiative to offer premium standard of reliability	1. Customer Request	1. Reinforce	1. Existing or New Specific Customer	1. Eco Eval	Enhance Eval

2.10 ECONOMIC EVALUATION MODEL

[FINALIZED: MARCH 6, 2000]

Issue Statement

In the new regulatory environment, distributors will face various requirements which suggest the need for a more commercially-oriented method of evaluating the economics and financing of Distribution System Expansion Projects. The issue is:

> What approach should be taken for the economic evaluation of distribution system expansion projects and what approach should be used to determine capital contribution from a customer or a developer?

The following are considered specific key requirements:

- Transitional Distributor Licenses obligate distributors to make a fair and reasonable offer to connect customers located in their licensed service areas to their distribution systems.

- The OEB?s need for an appropriate regulatory tool such as the Distribution System Code, to minimize its regulatory burden by harmonization of system expansion practices across electricity distributors while recognizing intrinsic differences between distributors in Ontario; e.g., higher construction costs due to geography or terrain.

- The need to achieve a uniform approach to distribution expansion projects evaluation, regardless of size or scope of such projects. Major expansion projects are expected to comply with the yet to be proclaimed section 92 of the *Ontario Energy Board Act, 1998*. [It should be noted that Government Regulations are expected be announced simultaneously with proclamation of section 92, which would define the criteria for classifying expansion projects into major and minor.]

- Market participants, especially customers and distributors, will benefit from development of a uniform and transparent approach for economic project evaluation with submissions to the OEB when required. A standard approach would be key to an efficient project approval process for competing expansion projects.

Scope

The issue of economic evaluation of expansions is interrelated with many other issues including enhancements, contestability and offers to connect. This SOR touches on most of these issues. Separate SORs have been developed to address the other issues in more detail. A brief summary of these other issues and associated SORs are described below for context.

SOR-Economics & SOR-Enhancement

This Summary of Recommendation (SOR - Economic) focuses on the economic evaluation approach for distribution expansion projects, while a companion (SOR - Enhancement) focuses on evaluation of system enhancements of such projects. Table 1 (on next page) delineates the two types of evaluations and outlines some examples of projects and the corresponding evaluation emphasis.

It should be noted that projects designed to accommodate new customer(s) or to accommodate load growth attributable to identifiable customers or groups of customers will be evaluated primarily on economic parameters. Distribution Expansion Projects to restore reliability and power quality to acceptable standards or to relieve congestion would be evaluated on the evidence of the system conditions prior to and after project proposed implementation date.

Table 1:
Project Evaluation Categories and Evaluation Emphasis

Project Category	Evaluation Emphasis	
	System Enhancement Evaluation	Economic Evaluation
Projects to: _ Improve Reliability, Power Quality or asset life replacement _ Relieve Congestion due to system wide load growth	Primary	Secondary
Projects to: _ Accommodate existing specific Customer Demands for Increased Capacity _ Connections e.g. new subdivision. _ Accommodate load growth due to new customers	Secondary	Primary

Appendix A of this document provides a detailed approach to unbundling projects that include various distribution system investments. It describes how *hybrid* projects may be untangled to reveal the system expansion activities that can be linked to identifiable beneficiaries.

Contestable Activities

The topic of contestable activities, including process, protocol and options available to customers when sourcing for competitive bids for such activities is not covered in SOR; the topic is covered by a separate SOR. The separate SOR also outlines the interdependencies between presenting the first round results of running the economic model with the distributor's estimated capital costs and the required customer capital contribution and the options available to the same customer at that point (see SOR on Contestability of Construction Work Performed by a Distributor).

Embedded Generation

The evaluation of embedded generation costs are addressed in the SORs of the embedded generation subgroup.

Options

1. **Lassez Faire Approach:** Allow each Distributor to have complete freedom and autonomy, to formulate its own economic project evaluation guidelines and capital contribution policy.

2. **Guidelines Approach:** Develop a set of guiding principles, and steps, for economic project evaluation covering capital contribution . These guiding principles will be included in the DSC.

3. **Prescriptive Approach:** Develop a detailed approach that prescribes the principles and implementation details, for economic project evaluation including determination of capital contribution amounts. These principles and implementation details will be included in the DSC.

Background Information

Implications of the New Paradigm

The restructured electricity industry offers the municipal owners of electricity distributors the opportunity to transform them from public utilities overseen by commissioners to registered commercial corporations. This represents a major paradigm shift for most distributors and will require fundamental changes in managing their business. The existing paradigm created incentives for distributors to focus on keeping retail rates as low as possible. In that environment, there was no incentive for distributors to either optimize their capitalization or attempt to maximize their financial returns. The new paradigm will create incentives for distributors to optimize their capital structure to achieve appropriate levels of leverage and to examine their financial returns very closely in order for them to meet shareholder objectives and expectations. Capital expenditures is one of the key areas in this new paradigm that needs a decision support system anchored in economic evaluation methodology. This pointed to the urgent need to formulate an economic evaluation approach for capital expenditures that recognizes the time-value of money. Such economic evaluation must also comply with the new regulatory requirements covering distributors' core businesses which is expected to call for a consistent and transparent approach for determining allowable capital contribution associated with investments in distribution system expansion.

Historical Approach to Electrical Distribution System Expansion

Distributors are expected to continue with their existing practices of meeting customer demands, which include distribution system expansion, until proclamation of the new regulatory environment by the Government, which is currently expected in the fourth quarter 2000.

The old regulatory regime under Ontario Hydro required that capital investment be identified and reviewed as part of "Use of Funds." Approval of such capital investments was subject to criteria designed to ensure that:

1. The expenditure was for the distribution of electricity and not for the purpose of engaging in other businesses.

2. Capital investments were not in violation of any contractual obligations such as the exclusive supply by Ontario Hydro.

3. Financial viability of the applicant MEU distributor was maintained;

4. Customers of that MEU distributor were protected from undue cross subsidization (e.g., between old and new customers).

The old reporting system was fully computerized and covered preparation and submission of a distributor's application for "Rate Adjustment" and/or "Use of Funds." A step-by-step procedure was available to MEU distributors via a computerized program, for electronic submissions, entitled "Utility Forecasting & Approval Program or UFAP." Distributors had various planning tools including "planning guidelines" available from their voluntary trade association - the Municipal Electrical Association (MEA). These guidelines cover principles for planning system expansion including economic evaluation techniques (using Discounted Cash Flow approach) designed to help ***choose*** a least cost option among competing alternatives.

Existing Approach to Natural Gas System Expansions

Prior to delving into the issues surrounding system expansion in electricity distribution, the DSC Task Force examined the approach used in Ontario to deal with natural gas system expansion by Local Distribution Companies. This step was undertaken to glean the basic principles used in the gas industry and explore which aspects of that approach are valid for the electricity distribution industry.

A presentation on September 29, 1999 to the DSC Task Force (see details in Minutes of Meeting #13), by OEB staff[4], covered "Background and Principles of Regulation of System Expansion in the natural gas industry" as well as potential implications on distribution expansions rising from new regulatory regimes for Electricity Distributors (e.g. "First Generation Price-Cap PBR").
The Session included a discussion of "Practical Issues regarding EBO 188 which governs project assessment for natural gas system expansion" with two Staff from Enbridge Consumers Gas (Norm Ryckman and Trent Winston).

The session also touched on the parallels and departures between these two industries and likely implications on the distribution industry in Ontario. It was noted that natural gas utilities are able to choose to serve or expand whereas electricity distributors are obligated to serve.

Principles that have potential to be applied to electricity projects:

- Standardized approach to DCF (Discounted Cash Flow) analysis. The DCF analysis is what the OEB has relied upon for 15 years;
- Common contribution policies, such that there are some rules around how the utility would collect, how much and from whom;
- Some common filing and reporting requirements on the system and the projects that are being done;
- The principle of avoiding cross subsidization between existing and new customers in the Natural Gas approach for system expansion should also be considered for the electricity distribution industry.

Principles that may not apply to electricity projects:

- Portfolio approach-assumes utility decides where to serve. The Portfolio was intended to balance high and low profitability projects so as to decide which areas should be served. The electricity provider has an obligation to make an offer to connect all customers within their service area;

4 Neil McKay -Manager, Facilities and Mike McLeod - Team Leader, Strategic Services

- Rate case filings and monitoring. Under Price-Cap PBR, there would be some reporting requirements in parallel with those resulting from an economic evaluation process; however, rate case filings would no longer be the focus.

After reviewing the background materials, subcommittee members decided to explore a forward looking economic evaluation approach for projects. The members were satisfied that the basic tool used today to evaluate natural gas project expansion also has been used in the past by various electricity industry participants. For example, Ontario Hydro used this approach to examine economic impacts of new general service customers on its rates and to determine whether or not capital contribution would be needed to prevent cross subsidization.

Summary of Discussion

Currently, distributors that do not collect development charges, fund distribution system expansion and rebuilding of infrastructure from rates revenue. Most distributors collect some or all of the costs to build a new subdivision from the developer. Connection costs are not addressed in this SOR. Generally, connection costs are for the plant to connect the new residential service, apartment, commercial or industrial building to the distribution system on the road allowance. Most utilities collect some or all of the costs to connect a new residential service, apartment, commercial or industrial building, to the distribution system.

Distributors historically have treated costs associated with what has been referred to as "on site" different to "off site" or "upstream" costs. On-site costs were usually paid for by the developer as capital contribution; offsite costs often would be collected by way of development charges through the Development Charges Act.

Moving forward, a distributor should have distribution rates to be able to fund distribution system rebuilding or replacing infrastructure from the revenue from rates. This concept should also be able to be applied to new distribution system built for new subdivisions, a new customer (s) at the end of a line or system expansion for an easily identifiable load increase by an existing customer. Some utilities will not have sufficient revenue from rates, possibly due to lower rates or due to collecting development charges. If the expected revenue from rates will not pay for the cost of the distribution system expansion, then the shortfall can be made up by capital contribution from the customer (s) or developer (s). Alternatively the distributor may choose to make up all or a portion of the shortfall itself.

Where an expansion supplies only a single customer at first (such as the rural area or a new industrial subdivision), the capital contribution required may be quite high. An SOR is required to discuss a means to either rebate the customer as future customers connect within a reasonable horizon or develop a different mechanism to collect capital contributions from the customers.

Why Should Expansion Activities be Subject to Regulatory Oversight?

The subcommittee members probed the potential benefits of having regulatory oversight over expansion activities:

- Helps to ensure that distributors undertake a thorough economic feasibility study (to the benefit of the market and rate-payers) of proposed capital expansions before proceeding with the work.

- Expansion involves new capital facilities; thus, there is potential for future stranding. This effect can be mitigated by avoiding duplication and/or overbuilding by more than one distributor and efficiencies of sharing of facilities should be encouraged where appropriate.

- An expansion may result in a capital contribution from a customer. This contribution is not part of a rate schedule that would be approved by the OEB.

Selection of the Discounted Cash Flow(DCF) Approach for Project Economic Evaluation

Alternatives for economic evaluation of distribution system expansion, including calculation of potential capital contribution by new customers, should include revenues, expected capital expenditure, and expected Operation & Maintenance (O&M) expenditures associated with a project in order to quantify the costs and benefits of any undertaking. Any attempt to require customers to contribute towards system expansion, without a transparent methodology, would be disputed. In addition, any approach that is used must capture the time value of money. The group endorsed the approach that the economic evaluation of a project application should rely on calculating its Net Present Value (NPV) using project-specific discounted cash flow (DCF) analyses.

In addition to assessing economic feasibility of an expansion, the analysis also could be used to determine the appropriate level of capital contribution. Capital contribution may occur when the NPV of a project is less than zero. The committee also agreed that any uniform model should be capable of reflecting local conditions and their impacts on the capital construction costs and ongoing O&M costs (e.g., rocky terrains or heavily treed areas).

Discussion Results: Explore in detail an economic project evaluation model using a DCF approach.

Matching Revenues & Costs for DCF Evaluation
[Incremental Attributable Capital Expenditures and Revenues]

In its simplest form, the economic evaluation of a project is based on the NPV[5] (Net Present Value) of revenue from customers attached to a project less the NPV of capital costs directly associated with the project and the NPV of future O&M costs. This can be represented as:

NPV of Project =
NPV Incremental Revenue from the project - NPV (Capital Costs + O&M Expenses)

There was much discussion regarding the type of model to be used: what should be considered in a model and what should be excluded. The common elements of various discussions have been grouped together in the following sections to develop principles of the modeling to be used by distributors.

Principle: The economic evaluation and the resulting financial implications should be based on matched incremental revenues and costs (i.e. "incremental project capital expenditures" and "associated revenues" and "O&M expenses" attributable to the project). The matching principle states:

- It is appropriate to include revenues from new customers connected to new facilities in the economic evaluation for each new project.
- It is inappropriate to include prior (historic) capital expenditures, considered sunk costs, or revenues from connections in prior periods. Exclusion of sunk costs and revenues from new customers connected to existing facilities will maintain matching between costs and revenue. In effect this will result in isolating the specific project and its economic feasibility.

[5] The net present value is equal to the present (or discounted) value of future cash flows. The net present value (NPV) is arrived at by discounting future cash flows (that is, revenues, costs, capital expenditures) by a certain rate. This rate represents the cost of financing the project including interest and equity costs. The NPV represents the gain to be derived for a project, over and above returns (costs) of the invested capital (debt and equity). As such, a positive NPV (greater than $0) means that the project is forecast to generate more than its costs including required financing. In essence, this discounting is the reverse of calculating compound interest. Compounding takes an amount today and grows it into the future at a certain rate. The net present value method, also known as discounted cash flow (DCF), is the most widely accepted means of evaluating projects.

Common Elements of Discounted Cash Flow (DCF) Calculation

The cash flow elements as outlined in Appendix B are appropriate for the DCF model. The following is a summary of the discussions regarding these parameters:

Maximum Customer Connection Horizon

A 5 to 10 year forecast horizon was considered. A five year horizon is thought by some as somewhat short as it may, in some cases, result in a "free rider" scenario for customers that could be projected to connect after the five year period. Others thought that a longer period such as 10 years may lead to high forecast errors.

Discussion Results: Customer connection horizon will be five (5) years.

Maximum Revenue Horizon

A maximum customer revenue horizon of 20 to 40 years was considered. The notion that the revenue horizon should reflect the average useful life of distribution facilities was debated. A table extracted from "Accounting for MEUs in Ontario" depicts the "Depreciation Rates" and "Life-Years" of Major Distribution System Elements and was useful in considering a revenue horizon that would match the average useful life of equipment. In the table, 25 years reflected the useful life of most distribution plants, except for Distribution Stations (below 50 kV) which is 30 years and Transformer Stations which are 40 years. Also discussed was the use of a "Vacancy Rate," when premises are empty and revenue is not being collected for installed plant, as a means of dealing with revenue risk. Such statistics are available at the municipal level for residential, commercial and industrial customers. It should be the responsibility of the distributor to demonstrate that their service area historically has been subject to vacancy rates that impact materially on the revenue forecast.

Discussion Results: Maximum revenue horizon will be 25 years. Vacancy rates may be used to deal with impacts on revenue of vacancies during the study horizon if the distributor has supporting statistics that demonstrate material impact on the revenue forecast.

Discounting and the Appropriate Discount Rate

In order to use a Discounted Cash Flow model, the method for calculating the appropriate discount rate must be specified. There was general consensus that a discount rate equal to the incremental after-tax cost of capital should be used.

Incremental weighted average cost of capital (WACC) refers to the anticipated cost of capital using the prospective capital mix and associated costs. This is in contrast to an embedded WACC which reflects the current actual cost of capital. For example, contrast the basket of existing debt that is carrying an average interest cost determined by the cost of debt at the time of borrowing and its current proportion in the mix. One distributor may have borrowed long-term debt when rates were high, in contrast to a distributor that has only recently borrowed at lower rates. By using the incremental WACC, this more closely matches the discount rate to the forecast cash flows. However, the embedded WACC may be easier to calculate. Under EBO 188 (the gas model), an incremental WACC is used; however, actual application may vary.

There is also the question as to whether the discount rate should be a "real" discount rate or a "nominal" rate. A real rate subtracts out the component that compensates for inflation. This can be a difficult exercise as it requires selecting an appropriate inflation index as well as a forecasting source.

As discussed below, escalation due to inflation will not be taken into account in the forecasts of revenues and costs. Thus, a theoretical argument can be made that a real discount rate should be used for matching purposes. However, this would add undue complexity especially given the current low inflation environment.

Discussion Results: The distributor's nominal after-tax incremental weighted-average cost of capital should be used as the discount rate.

Escalation Factors

There is a question as to whether revenues and costs should be escalated due to forecasted inflation, specific or general. Escalation adds a further layer of complexity on top of what is already a long-range forecast. Little would be added by incorporating escalation factors. In fact, by adding a further forecasting dimension, consistency and comparability of forecasting, and thus results, may be compromised.

Discussion Results: Revenues, operating costs and capital expenditures should not be escalated. However, an off ramp should be considered in periods of high inflation.

Capital and Operations and Maintenance Costs (Attributable to Projects)

There was general consensus that O&M costs should reflect only direct burdens and overheads related to the project; general overheads are not relevant in the DCF evaluation. An implementation issue with respect to the estimate of the attributable O&M costs, is that the distributor will have to break out the design and engineering costs from the O&M costs.

Distributors will need to articulate what costs should be included in the evaluation as attributable O&M costs (what expenses are appropriate to go into which accounts under the Uniform System of Accounts, and which accounts are appropriate to be the burden charged to the project). Unbundling the direct construction costs, engineering costs and administrative costs applicable to the project may provide a different result for different distributors. There is an element of discretion as to which Uniform System of Accounts account the distributor assigns the costs attributable to the project. As an example, some distributors use a burden on labour that includes overall equipment, others might use a burden attached to labour and another burden attached to equipment.

Distributors should be required to present their estimate in a manner such that their different components are clear and identifiable (e.g. engineering, administrative, construction, O&M, etc.). Over time, if there are discrepancies noted between distributors, there will be marketplace pressures exerted on the distributors to reduce their costs or conform to the distributor standard.

The subcommittee examined two options for estimation of capital and O&M costs attributable to projects:

- Leaving the estimation of the appropriate attributable O & M costs to each distributor to use its judgement as to the appropriate amount for each project based on its own most recent history; or
- Using the Uniform System of Accounts (US of A) as a means to arrive at the appropriate levels of the O&M costs in a consistent and transparent manner.

It became clear that the two options converge, since the source of obtaining costing information on various O&M activities is the Uniform System of Accounts. The data a distributor would need will vary by a project's scope and size. A preliminary investigation by the group indicated that such O&M information will be available through the Uniform System of Accounts. It was recognized that there may be some amount of variation across distributors, due to the discretion allowed in dealing with the burden accounts.

Discussion Results: It is recommended to use the "Uniform System of Accounts" to obtain consistent and reliable estimates for the O&M expenditures.

Capital Replacement Within the Study Horizon

A discussion touched on the issue of whether or not to include a component that reflects replacement of system components due to failure. The discussion also covered the possible need to forecast failure rates (which includes O&M and Capital dollars). If some assumptions have to be made on asset replacement, a failure rate could be estimated to recognize those costs. However, concern was raised that an overstated need for capital replacement will drive up the capital contribution unjustifiably, especially since the 25-year revenue horizon was chosen to reflect average useful life of distribution system elements. This reflects a reality that some system components will last less than the average while others will last longer.

Discussion Results: It is recommended not to include capital replacement estimation in the model because it could be considered double counting in light of the fact that average useful life of assets are recommended.

Hybrid Projects

The vast majority of project undertakings are a mix of activities that may include:

- <u>Reinforcements</u> to accommodate new load;
- <u>System expansion</u> to connect new load;
- <u>Replacements</u> of system elements that are at, or exceed, estimated useful life; or
- Distribution system <u>enhancements</u> to restore power quality or distribution system reliability to acceptable standards.

Hybrid projects will always be carried out to minimize distributors' costs. The task is to unbundle the costs of such undertakings to isolate true system expansion activities so that an economic assessment can be carried out. To aid this task, the members assembled a comprehensive sample of distribution system activities that were mapped by:

- Key Project Driver;
- Activity Category such as System Expansion, Reinforcement, Replacement or Connection;
- Beneficiary - New Customers, Existing Customers or both; and
- Designated Primary Evaluation approach - either Economic Evaluation or System Enhancement Evaluation.

Principle: Hybrid projects involving system expansion must be unbundled to identify true system expansion costs.

Discussion Results: **Cost Tracking By Mapping Activities**. Attachment 1, Appendix A of this document, should be used to help untangle Distribution System Activities that usually are executed within the same time period on one or more system elements. It summarizes the steps and lists illustrative examples of such mapping.

Project versus Program

Some undertakings involving sustainment or development programs span a period of time much longer than expected project time (e.g., 2 years). The group discussed if these programs ought to be treated as a single project for the purpose of performing an economic evaluation of such an undertaking. There were two opinions expressed regarding treatment of this topic:

1. Define Projects in such a way to include all aspects of programs in that definition;

2. Keep the two definitions and ensure that programs are included in the Economic Evaluation.

Principle:

General agreement was reached that where a program exists, the program will be evaluated; it cannot be parceled. Applying the "Matching" principle and the "Cost Tracking by Mapping" principle require that any distribution work, which is part of a program (and its related costs) that is attributable to an expansion project, must be included in the project's economic evaluation along with expected matching revenues.

Discussion Results: Consensus was reached to define "Project" in such a way that it captures the characteristics of programs. This is critical for major undertakings that are potentially subject to section 92 of the *OEB Act, 1998,* to avoid parceling of such activities into smaller components for the purpose of avoiding approval of the entire undertaking.

Connections Program Approach Versus Project-by-Project Evaluation

The concept of "pooling" forecasted new customers over a one year period and related "system upgrade/expansion" costs are a potential means to reduce the amount of effort to process applications from new customers. The following issues were discussed:

- In a pooling program like this, the distributor would need to carry debt between the time the expansion is built and when new connections are required.

- This approach would result in perpetuating cross subsidization between new customer developments, where <u>all</u> new customers pay for <u>all</u> expansion costs in that year.

- How will infill customers be accounted for? Who carries the debt until new connections come on line?

- The starting point for distributors is not uniform since the starting rates are not equitable - Some utilities have always factored all growth-related costs into their rates while others have chosen to reduce their rates and collect capital contributions instead. There are also some distributors that have reduced their rates by collecting Development Charges.

A rural example was discussed regarding individual extensions. Due to forecasting challenges in rural and remote territories, some distributors have adopted a rebate policy. In one such policy the customer who is charged contributions in aid of construction may take on a 5-year quasi-insurance agreement with the distributor who will administer it for a fee. The customer pays 100% contributions up front for the construction of the extension, and will receive rebates as others tap onto the facilities. The agreement can be renewed at the end of the 5-year period for another 5-years. The group identified policies such as these as an implementation issue for administering capital contributions from customers.

There is concern by the largest rural distributor in Ontario that implementation of such an approach on a per-project basis would require a significantly high effort level. A more simplified approach might deal with all expected additional customers over a one-year period and calculate, ahead of implementation, a uniform "Capital Contribution" amount. The group felt that again this was an implementation issue and that individual projects should be evaluated on their own merit. This item will be dealt with further under the SOR on Capital Contributions.

Discussion Results: The individual project based evaluation approach is recommended, to match customers to associated expansion costs and possible capital contribution requirements.

The "Next" Customer needs new Capacity or the "Straw that breaks the Camel's back"

The group had difficulty dealing with the scenario of capital contribution required when an expansion due to the new customer load, requires an upgrade or building of a line and may need a new breaker or a Transformer Station (TS) expansion. That may limit the location of where a customer builds if the build requires a capital contribution to cover the cost of a new feeder breaker or a TS expansion.

One option is to have expansions to the transmission system or to the Transformer Stations to be done under a scenario similar to the expansion guideline for distributors. The Transmission Company could respond to the expansion need by looking at the cost of building a standard feeder breaker or a standard Transformer Station that is their normal lowest capacity standard that meets the needs of the load. Similar to distributors, a transmitter would have to look at the present value of the revenue that would be gained from the load that the TS expansion would supply less only the value of constructing the TS expansion that is attributable to the capacity needed by the distributor. If the economic evaluation results in a shortfall of revenue to cover the appropriate capital costs attributable to the distributor, then the transmitter would be able to ask the distributor for a Capital Contribution.

Another option is to have a small portion of a connection charge collected by the distributor based on the capacity required by the customer to help fund the requirement for capacity increases. This would spread the burden of the cost to increase TS capacity across all customers rather than the "next" customer that causes the need for capacity increase.

A third option is to have TS capacity increases covered under the pooled costs and rates of the transmitter, as they have been in the past. The cost of building TS capacity is in the cost of power to distributors today. If this concept is to be discontinued, then the transmission rates charged to distributors, should decrease accordingly. This rate could be charged to customers directly to pursue the option noted above.

Discussion Results: The group felt that the pooled concept for TS capacity, should continue as a responsibility of the transmitter as part of the unbundling of existing rates. This recommendation should be forwarded to the TSC Task Force and the OEB Staff that are involved in the Transmission Rates Hearings with OHNC. It is recognized that some upcoming decisions regarding transmission and distribution will impact on this suggested treatment in that, some utilities do both.

Issues around Modelling

Providing appropriate incentives for distributors to continue to build systems in a prudent fashion

The group discussed whether the PBR regime provided the proper signals so as to provide incentives to a distributor to design and build systems in a way that considers and balances current customer load with potential future load growth. The crux of this issue is that distribution systems can be more economically built to accommodate future growth at the outset of a project rather than having to incrementally enlarge a system or rebuild a system throughout the life of assets. The uncertainty arises because clearly distributors cannot know with complete accuracy how load will grow within its territory.

The group considered the following scenario:

A distributor designs a system to meet currently identifiable load growth in a specific area of its service territory. There is considerable uncertainty regarding whether further load growth with occur within or adjacent to the area. The distributor is aware that further subsequent load growth might require a rebuild of the original line. If the rebuild occurs within a short time frame of the original build, it may require the line to be removed and rebuilt and the total cost to remove and replace the original line is much more expensive than to have built originally for future capacity. There was considerable concern that the economic drivers contained within PBR and the economic evaluation model contemplated by this group would drive management to build only for the new load that was understood with certainty, and that this could drive up the cost to supply future loads.

The group recognized that the economic modelling contemplated by the DSC was intended to drive distributors to make rational business decisions with due consideration to the inherent risks and rewards both to them and to ratepayers. Thus, when considering expansion related expenditures, the distributor would want to do some "what if" scenarios relative to subsequent development so as to determine the inherent risk to the distributor of designing and building the system at various sizes.. That is, the distributor would develop an economic evaluation formula, based on the OEB defined model, with the OEB defined parameters for the known load requirements. The distributor would do a subsequent "what if" scenario to see whether they could demonstrate to the corporate owners the prudency of building enough 'extra capacity' to accommodate future growth, which might occur with some estimated probability.

The group recognized that the current regulatory regime might in fact drive utilities to under-build so as to minimize corporate risk of future stranded investment and unrecovered costs. The group considered this an implementation issue, since there is a recognized societal cost associated with potentially under-building (as identified above). However, utilities may have 'overbuilt' their systems in the past, and there may have been a societal cost associated with this overbuilding. Indeed, there seemed to be the potential for a 'swing' between one extreme or another, and ultimately the group agreed that the regulatory regime should strive to be have as neutral an impact as possible on corporate investment decisions. It was hoped that the economic modelling should provide a framework for companies to do economic feasibility studies, and calculation of customer contribution, but that good utility management should prevail in terms of the design of the system so as to minimize total project costs over time.

In an effort to address this "pendulum" effect, and mitigate the risk, the group discussed the merits of extending the customer connection horizon to 10 years from 5 years. In so doing, the fixed infrastructure costs would be spread over a greater number of customers and the capital contribution per customer would be reduced. However, it was recognized that the accuracy of forecasting beyond the proposed five year connection horizon might become very speculative.

Discussion Results: The group agreed that the connection horizon should stay at five years for better accuracy of forecasting. Prudent building for extra capacity should be dealt with by each distributor as an implementation issue based on their growth history and the risk tolerance of their governing Board. It is hoped that the economic evaluation model discussed in this SOR will have a neutral impact on management decisions, and that distributors will continue to prudently plan and build for reasonable future growth.

Capital Cost Allocation (Attributable Approach)
*[Avoid Potential Customers***?** *Capital Over Contribution]*

There are various means to deal with items that can cause customers to over contribute towards an undertaking. It is helpful to view this as a special case of **?**Hybrid Projects**?** except that it exclusively focuses on future events. In order to ensure that today**?**s new customers do not subsidize future customers, the following three methods were considered and discussed:

- The advance/delay of costs of system elements. This approach would attribute the carrying cost of investment for the period of time a project is advanced to accommodate a new development. An example is a new subdivision that requires a new feeder in year 1 of the study, and this in effect advances the in service date from year 3 to year 1. The carrying costs of the investment (new feeder) for 2 years is the attributable capital costs.

- Terminal Values. Terminal Values can be used when investments in system elements occur whose useful life far exceed the revenue horizon (e.g., Distribution Stations or Transformer Stations).

- An Allocation Approach. Capital Construction Costs can be allocated for system elements where the capacity of the proposed facilities exceed those required to meet current customer needs. In other words, the portion of the project required for future customers should be allocated to the future customers.

Principles:

(1) Customers should not be responsible for ?Incremental Cost of Oversizing?.

(2) Today?s new customers should not subsidize future customers.

(3) Existing customers should not subsidize new customers.

(4) The distributor should be at risk for financing system overbuild (i.e., system investments in anticipation of customer connections beyond the Connection Horizon).

Discussion Results: The attributable cost should reflect the cost of a system with a standard design that is closest in capacity to the development under consideration.

Design Standards

The group discussed the merits of the need for the distributor to establish consistent design standards to be used in system expansions. There are a number of reasons why consistent design standards are important:

- The costs of system building would be driven by whatever design and construction standards a distributor utilized. These should be clearly articulated and understood;

- There are efficiencies with respect to having construction standards throughout a distributor's service territory.I In having similar equipment, a reduced scope of inventory would need to be maintained and the specialized operating and maintenance knowledge would be developed;

- Load customers' and developers need to clearly understand the system standard because they may be able to request either a lower or higher standard, but the distributor would have to have reason to justify a deviation from the norm;

- Consistency in planning to defined and certain design standards may also prevent a utility having to rebuild their system several times over the long term;
- In specifying that the design of the system would be in accordance with the utility's standard practices across their system, there would be an avoidance of either a deterioration of the system or an over building or "gold plating" of the system; and
- Distributors may need to define design standards for a third party for work that is contestable.

In summary, the group felt that existing or prevailing planning and design standards should be specified and referenced in the Conditions of Service so that customers knew what the distributor would buildfor a system expansion. At the same time, the rules should not impair good system planning, but should create incentives for changes that improve the system plans, if necessary. The group hoped that the PBR regime would eventually balance reliability and system efficiencies, but recognized that in the short term, the current PBR regime may not provide sufficient financial drivers to promote adequate spending by distributors to ensure continued or improved system reliability. Some members expressed concern that the current PBR regime may create incentives for distributors to relax their current standards to "come down" to the standards defined in the PBR handbook. It is therefore important to ensure that the DSC specified current design standards as a minimum approach for utilities to use so as to minimize deterioration of the system.

There was a long discussion around the connection horizon and the "collection horizon". The question of connection horizon vis-a-vis the use of design standard was debated. Specifically, the design standard in some cases might lead a utility to build the system in a way that actually provides more capacity than an identifiable benefactor needs. In this case, it would be difficult to assign costs to benefactors. This latter could be addressed through the use of a longer 10-year horizon for the forecast of customer connections, so as to spread out the debt over a longer period.

Discussion Results: The group struggled with the need for a design standard since it was dealing a "balancing act" between: overbuilding; /underbuilding; short term versus long term planning; fairness to customers versus risk mitigation to distributors; and the administrative cost of monitoring the customer contribution versus the cost. These design standards should be documented clearly and available in a format that is referenced in the Conditions of Service for the distributor.

Horizon for Capital Investment

Capital Investment that reflects staged construction often occurs where real estate developments is in phases. For example, certain expenditures may occur at the beginning of the project (e.g., 3-phase main feeder in year 1 feeding all future loads within the 5 year horizon and also the first subdivision), while other expenditures occur at a later date (e.g., in year 3, a single phase lateral is built to supply the second subdivision). It is recognized that capital expenditures may be staged in line with customer connection and revenue forecasts.

Discussion Results: Capital Investment should be recognized in a model when it is expected to occur.

Risk Management By Distributors For Expansion Projects

The subcommittee acknowledged the need for appropriate risk mitigation in distribution system expansion undertakings. The principle of attaching risk proportionally to the amount of economic gains should be kept in mind in developing an approach or policy.

Subdivisions are a major expansion activity for most distributors and one which entails some degree of risk that houses are not built as expected after the lots are all serviced. It was generally felt that developers, rather than distributors, should bear this financial risk since they were in the business of providing these serviced lots and the decision whether or not to proceed with a particular development rests with the developer. This would seem to imply that developers should pay the full initial cost of servicing their subdivisions with perhaps a refund (depending on the distributors capital contribution policy) as each house is connected. In many municipalities, the developer currently pays full initial servicing cost for the distribution system in a new subdivision.

A subcommittee's telephone survey indicated that a <u>wide variety of practices</u> are used by the utilities to mitigate risk including:

1. Security bonds;

2. Letters of credit; and

3. Joint bank accounts, with money deposited by the developer to cover the construction cost, and payments are cosigned by the developer and the utility.

Discussion Results: A separate SOR covering Capital Contribution will deal with this issue (see discussion below, under Capital Contribution).

Capital Contribution

Consistency and fairness are best achieved by adopting an approach of calculating the contribution amounts based on economic criteria (i.e., a DCF calculation). However, there was no consensus as to whether or not collection of the capital contribution is mandatory. Some members felt that fairness and equity among new customers as well as between old and new customers requires a mandatory approach regarding capital contribution. The two alternatives that the group discussed were:

1. Distributors are obligated to charge beneficiaries (customers) for DCF short falls;

2. Distributors may choose to require capital contribution up to the specified maximum amount (i.e., DCF short fall). The Distributor may choose alternative financing strategies to bring a project's NPV to zero (0), include raising new debt or equity.

The group discussed various approaches to obtain capital contribution in aid of construction including periodic contribution charges or a lump sum payment up front.

The subcommittee enquired about, and confirmed, that in the future, municipalities that may be owners of the distributor companies can make capital contributions towards projects or developments. However, such contributions will not be included in the asset base. This is simply applying the principle of separating the wires business from all other activities of the holding company (the municipality in this case).

Discussion Results: The subject of a distributor's obligation to collect capital contribution and from whom will be dealt with under a separate SOR.

Staging Issue

The group recognized that capital expenditures may be staged in line with customer connection and revenue forecasts. Concern was expressed over shortfalls on staged developments that require a distribution system prudently built with capacity to accommodate future load growth forecasts beyond the allowable "Connection Horizon." The group discussed an example, when the municipality received plans for three sub-divisions and a distributor needs to construct a feeder line to service those developments. In year 1 the distributor starts planning and constructing for the first development may be started in year 2, the second development in year 4 and the third development beyond year 5. The issue is who pays what and when?

If less than 100% of the total forecasted energy users are expected to connect within the first 5 years, perhaps the developer(s) of the staged undertakings could be charged proportionately for the shortfall of cost to build vs revenue needed to support the infrastructures. Another method is to build only the distributors system needed for the known development. When the other developers are known at a later date, the feeder system can be built to service the increased load. This may result in reconstruction work in the first development and an increase in the total cost of the project due to excavation and restoration costs in the established subdivision. In exploring options, key considerations should be "what triggered the capital investment" and "who benefits."

The primary issue from the distributor viewpoint is risk-mitigation against developer default. Potential options include:

- If all developers are known, they all can share proportionally in any shortfall.

- If only the first developer is known, the developer may pay all of the shortfall and collect from future developers.

- If only the first developer is known, the distributor shareholder may finance.

- If only the first developer is known, the municipality could finance.

Discussion Results: It is recommended that this issue be addressed in the SOR dealing with obligations on Capital Contribution.

Customer Demarcation Point (Ownership)

Discussion Results: Distributors will be expected to follow the DSC and identify the customer demarcation point (ownership). Also, policy regarding contribution in aid of construction will be premised on the customer demarcation point (ownership).

Outstanding Issues

The group identified outstanding issues that need to be addressed.

- Should we be making exclusions for emergency response work? Is capital work in response to an emergency subject to the recommendations being forwarded in this SOR? Potential solution: Perhaps this should be revisited in SOR-Enhancement.

- Transformation is a serious issue around "pure" connections. Where will the funding come from? Transformation is not easily attributable to any one customer. Potential solution: Perhaps the distributor should be given the leeway to define a "connection/offer-to-connect threshold" in his conditions of supply.

- Lies-along connection versus offer-to-connect: Does the obligation to connect only pertain when capacity exists to accommodate it? How can a single small load be attributed to a "customer contributed" reinforcement?

- Transparency may not require "full disclosure." What does it mean? What will it look like? This needs to be revisited when contestability of expansion work is discussed.

- Definitions need to be penned (e.g., system expansion, program, project).

- Distributors will face risks for costs considered "not attributable" for system expansions that features distribution facilities with capacities beyond that needed for new customers' needs within the "Connection Horizon" of 5 years.

Evaluation of Options

It is recommended that evaluation of each option be examined through its effect on key stakeholders, customers and various market participants as well as its effect on the effectiveness and efficiency of the regulatory process.

Aspect	Option 1 *Lassez Faire*	Option 2 *Guidelines*	Option 3 *Prescriptive*
Amongst Distributors ***Consistency*** of **Economic Evaluation** Results & Capital Contribution amounts	Consistency of Results is likely **Non-Existen**t	Consistency of Results is likely **Medium**	Consistency of Results is likely **High**
Developers/Customers ***Degree of Comfort*** regarding **Expansions requiring Capital Contribution/Transparency**.	**Low** Degree of Comfort	**Medium** Degree of Comfort	**High** Degree of Comfort
Effort Level for Setting Up Economic Evaluation Approach and Systems By Distributor?s Staff	**Not Applicable** (Varies)	**Medium** Effort Level	**High** Effort Level
Degree of Discretion For Distributor Staff in **Setting Up Economic Evaluation Processes**	**High** Degree of Discretion	**Medium** Degree of Discretion	**Low** Degree of Discretion
Efficiency of **Regulatory Oversight** - Example is ability to compare competing projects vying to serve boundary areas.	**Inefficient** as it requires High Effort Level.	**Medium** Efficiency	**High** Efficiency

Implementation Issues

Customer Connection & Capital Contribution Policies: Part of the distributors' management of system expansion will be the provision of common customer connection policies consistent with the DSC. These will include Board approved policies, applicable to all customer classes, relating to customer contributions to otherwise financially unfeasible projects. These policies may best be communicated to the customer in the Conditions of Service.

Availability of Evaluation Spreadsheet: Should an economic evaluation spreadsheet based on the sub-groups recommendations be made available to all? (If not, this is not an implementation issue)

Transitional Implications: Transitional implications due to inequitable starting points in terms of existing practices amongst MEU distributors regarding capital contribution policies. Distributors will have different rates depending on the amount of capital contribution they received for new projects. This impact may be quite large for utilities that collected Development Charges and accordingly lowered their rates. The group recognized that distributors with lower rates that have not covered the cost of system expansion, may either require more in capital contribution, or may need to seek more external financing or may need to make application to the OEB to increase rates to a level that acknowledges the loss of Development Charges revenue.

Rural Areas: For distributors that serve mainly rural areas it was felt that additional SOR's should be developed to deal with the following :

(a) Distributors that expect a large number of projects in any one year where each project is expected to need monitoring and tracking for at least five years (customer connection horizon), would require considerably more effort in administration of capital contribution than the existing processes. This higher effort level is required to reflect the unique requirements of each expansion.

(b) A rebate program would address concerns regarding the difficulty of forecasting customer connections over the "Customer Connection Horizon."

Forecasts: Accurate revenue forecasting will become important to forecast what revenue may be available from specific types of customers.

<u>Recommendation</u>

Option 3 (the "***Prescriptive Approach"*** option) is recommended. A detailed approach should be developed that prescribes the principles and implementation details for economic project evaluation, including determination of capital contribution amounts. These principles and implementation details should be included in the DSC.

1. Distributors should be required to perform an economic evaluation of distribution system expansion projects to determine economic viability of a project.

2. Distributors should develop their own Discounted Cash Flow models for economic evaluation based on the principal of Net Present Value of a project is the PV of revenue from customers that will be connected to a project less the PV of capital costs directly associated with the project and the PV of future Operating & Maintenance costs associated with the project.

3. Forecasting future customer connections should be based on the customers that the distributor expects to connect to the project within five years of the distributor energizing of the project (i.e., the five year customer connection horizon).

4. Forecasting future revenue should be based on the revenue from rates applied to the expected customer connections (5 year horizon) for a period of 25 years from the energizing of the project (25 year revenue horizon).

5. Revenues and Operating Costs should not be escalated for the purposes of the modelling. The model should use the distributor's incremental weighted average of after tax cost of capital.

6. Capital expenditures attributable to the project should reflect the cost of a system expansion with a standard design used by the distributor that is closest in capacity to the development under construction.

7. Design standards should be specified by distributors as those which were prevailing or prevalent throughout their current distribution system. These standards should be documented and available for public information.

8. Hybrid projects involving distribution system expansion must be unbundled to identify true system expansion costs.

9. O&M costs should reflect only direct burdens and overheads that will be related to the project.

10. It is expected that distributors will continue to plan and build for reasonable future growth in the distribution system.

The group further recommended that the existing pooled concept for maintaining existing Transformer Stations and for constructing new Transformer Station capacity, should continue as a responsibility of transmitters as part of the unbundling of existing rates. The DSC Task Force has asked that this recommendation be forwarded to the Transmission System Code Task Force and the OEB staff that are involved in the Transmission Rates Hearings with OHNC.

The rationale, description, and formulation of the above Option 3 are outlined in the "Background Section" as well as in Appendices A and B of this SOR. Appendices A and B outline the recommended economic evaluation process at a conceptual level while the "Background Section" delves more into the details and intricacies of key issues.

Voter Summary

Majority in favour

Dissenting Opinion

One member of the Task Force submitted the following dissenting opinion:

"After careful consideration I feel obligated to register a dissenting opinion against the Economic Evaluation Model for Distribution System Expansion. This opinion is in no way meant to make light of the hard work that went into forming this model. It is intended to highlight the significant impacts that will occur from the sudden shift in capital funding requirements for municipal utilities with high growth in their licensed service territories.

As you are well aware Municipal Utilities have typically funded new capital expansions by way of development charges, capital contributions or both. The new economic evaluation model now shifts the onus for financing new capital completely onto the shoulders of the municipal utilities. This is a significant change and municipal utility rates are not designed to produce a suitable return on equity to support high growth. The economic evaluation model does nothing to mitigate implementation impacts. If we go back to what started this deregulation process you will recall it had something to do with escalating costs and high rates. The Ministry of Energy, Science and Technology is already on record stating that municipalities/municipal utilities are squeezing electricity customers. Although we all recognize that a change in regulation is required, the economic evaluation model will create upward pressures on rates and subsequently cause rate increases which the Minister emphatically speaks against. Further, if the utility input rates are in question or even worse they are wrong then this would leave one to believe that the output would also be incorrect. Unfortunately given the time constraints on the task force to finish this process and the workloads back at our utility there has not been enough time to run actual data through the model. Only then would I be able to consider support of the economic evaluation model, and only if there were no negative rate impacts on our customer base."

APPENDIX A

Proposed Economic Evaluation Approach
For Distribution System Expansion

1. Project Drivers

All expansion projects related to distribution systems will be subject to system enhancement evaluation and economic assessment defined in this document with exceptions of projects dealing with relocation or reconstruction of facilities.

1.1 System Enhancement Driven Projects

Some system expansion projects are designed to restore, enhance and improve deteriorating reliability or power quality standards to acceptable levels.

System enhancement may also include: (a) conversion to higher voltage projects if the main driver is increasing reliability and reduction in losses; (b) communication system upgrades.

1.2 Projects Driven By New Customers' Load

Customer growth, from connection of new customers or from increasing load by existing customers, will lead to expansion of distribution systems.

Examples include:

- Conversion to higher voltage distribution systems to increase capacity in response to new customer connections or increasing loads.
- Construction of distribution facilities to accommodate a new residential subdivision or industrial park development.
- Construction or reinforcement of radial distribution facilities to accommodate a new customer or an increase in load at an existing industrial, commercial or institutional sites.

1.3 Mapping Hybrid Projects and Activities into Two Evaluation Processes [Economic and System Enhancement Evaluations]

Project undertakings by distributors are usually a mix of activities. Examples of such projects are: (i) reinforcements to accommodate new load; (ii) replacement of system elements that are at or exceeded its useful life; (iii) distribution system enhancements to restore power quality or distribution system reliability to acceptable standards. The objective is, to the extent practicable, to track attributable costs by mapping activities as outlined below.

It is recognized that a distributor's objectives of optimizing resources and minimizing their costs are achieved by incorporating various projects and programs in a single initiative or overlapping activities on the same distribution system component(s) e.g. Distribution Line. The task is essentially unbundling the costs of such undertakings so that the economic assessment for distribution system expansion can be carried out. Attachment 1 of this Appendix A lists a comprehensive sample of distribution system projects and activities that are untangled into Distinct Activities that are unique along three successive and distinct parameters (see items (i), (ii), (iii) below), which leads to the Primary and Secondary Emphasis of Project Evaluation (item(iv)):

(i) Key Project Driver.

(ii) Activity Category such as System Expansion, Reinforcement, Replacement or Connection.

(iii) Beneficiary - New Customers, Existing Customers or both.

(iv) Designated Primary Evaluation approach - either Economic Evaluation or System Enhancement Evaluation.

1.4 Project versus Program

Some undertakings involving sustainment or development programs which span a period of time much longer than expected project time (e.g., 2 years) will be treated as a single undertaking under section 92.(1). In other words parceling of such programs into smaller components will not be allowed for the purpose of avoiding approval of the entire program or undertaking. However, once the approval is granted, construction phases that may take place a few years subsequent to the initial Board approval, may require partial review by the Board at these points in time. An example of programs include voltage conversion to higher voltages.
The approach described above, in Section 1.3 of this Appendix A, to untangle/unbundle projects and activities is equally applicable to programs. Some programs would be included if they are considered attributable to the economic evaluation of an undertaking while other programs can be considered not attributable

to that same undertaking and thus would be untangled/unbundled from the costs of the undertaking.

2. Project/Program Evaluation

To protect public interest, the Board will need to be assured that system expansion projects benefits end use customer and rate-payers, and that it also promotes investment in system efficiency, reliability, and quality of service.

2.1 Emphasis of the Evaluation

Table 1 outlines primary and secondary criteria related to project evaluation. Proposed Projects to restore reliability and power quality to acceptable standards or to relief congestion would be evaluated on the evidence of the system conditions prior to and after project proposed implementation date. Proposed projects designed to accommodate customer connection(s) or to accommodate load growth attributable to identifiable customers or group of customers will be evaluated primarily on economic parameters.

Table 1:
Project Evaluation Categories and Evaluation Emphasis

Project Category	Evaluation Emphasis	
	System Enhancement Evaluation	Economic Evaluation
Projects to: _ Improve Reliability, Power Quality _ Relieve Congestion	Primary	Secondary
Projects to: _ Accommodate Customer Demands for Increased Capacity requiring Reinforcements _ Connections e.g. new subdivision. _ Growth in Load	Secondary	Primary

2.2 System Enhancement Evaluation

System enhancement includes projects being developed for security of the distribution system and for system reinforcement reasons.

Certain system expansion projects are designed to primarily restore, enhance and improve, to acceptable levels, deteriorating distribution system reliability or power quality standards.

The reliability and power quality driven projects are initiated by distributors and the evaluation will include evidence of performance prior to project implementation and a forecast of same after its implementation.

2.3 Economic Evaluation for Load Driven Projects

Economic evaluation of a project application will rely on calculating its Net Present Value (NPV) using project-specific discounted cash flow (DCF) analyses. In addition to assessing economic feasibility, the analysis will also be used in determining, the appropriate level of capital contribution. Capital contribution occurs when the NPV is negative (i.e., NPV is less than $0).

A consistent approach for economic evaluation of customer driven development projects is desirable as it offers:

(i) Similar customers equal treatments across the province. It also offers a consistent framework for capital contribution that can be applied to all such undertakings within a distributor's boundary.

(ii) Comparable methodology for evaluation of competing distribution expansion projects.

(iii) Common practice for the upcoming PBR environment.

Incremental Attributable Capital Expenditures and Revenues

The economic analysis and evaluation is intended to predict the financial impacts of project proposals by examining the *"incremental project capital expenditures"* and *"associated revenues"* and *"attributable expenses"*. It is therefore inappropriate to include prior (historic) capital expenditures, considered sunk costs, or revenues from connections in prior periods. Exclusion of sunk costs and revenues from new customers connected to existing facilities will maintain matching between costs and revenue. In effect this will result in isolating the specific project and its economic feasibility.

Hybrid projects will always be carried out to minimize distributors' costs. The task is to unbundle the costs of such undertakings to isolate true system expansion activities so that an economic assessment can be carried out.

- To achieve this unbundling it is helpful to follow the approach depicted in Attachment 1. In Attachment 1, a comprehensive sample of distribution system activities are mapped by: (i) Key Project Driver; (ii) Activity Category such as System Expansion, Reinforcement, Replacement or Connection; (iii) Beneficiary - New Customers, Existing Customers or both; and (iv) Designated Primary Evaluation approach - either Economic Evaluation or System Enhancement Evaluation.

- Construction in anticipation of future demand, beyond customer connection horizon, will not be funded by today?s new customers. Any ?incremental overbuild? costs need to be peeled off i.e. untangled/unbundled from the total costs.

- Definition of a "Project" will be stated to capture the characteristics of programs. This is critical for major undertakings that are potentially subject to Section 92. of the *OEB Act, 1998*, to avoid parceling of such activities into smaller components for the purpose of avoiding approval of the entire undertaking.

- Capital replacement estimation will not be included in the evaluation because it would be viewed as double counting, in light of the fact that average useful life of assets are utilized.

Operations and Maintenance Costs (Attributable to Projects)

Operation and Maintenance costs should reflect only direct burdens and overheads and that general overheads are not relevant in the DCF evaluation. Distributors should use the Uniform System of Accounts (US of A) to obtain consistent and reliable estimates for the O&M expenditures consistent with the project under consideration.

2.4. New Customers Connected to New Facilities

Revenues from new customers connected to new facilities should be included in the economic evaluation for each new project. Conversely, new customers connecting to existing facilities should be excluded from the economic evaluation of new projects. In other words, an estimate of the NPV without new customers connected to prior expansions will be required.

Customer Connection & Capital Contribution Policies

Part of the distributors' management of system expansion will be the provision of common customer connection policies consistent with Distribution System Codes. These will include Board approved policies, applicable to all customer classes, relating to customer contributions to otherwise financially unfeasible projects.

Consistency and fairness are achieved by adopting an approach of calculating the contribution amounts based on economic criteria where the common DCF calculation shows that a project's revenues will not cover its costs. The amount of Capital Contribution in such situations is that which bring a project's NPV to zero (0).

If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion within the specified "Customer Connection Horizon."

Customers Connected to Distribution Systems & Customer Demarcation Point(Ownership)

Distributors will follow the DSC to identify the demarcation point of the Customer Connection and distributor's system for which Contribution in Aid Construction Policies applies.

The criteria for contributions in aid of construction for all applicable distribution system elements will apply to all customer classes.

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the following:

(i) Requirements for payment for all, or part, of the reinforcement to the distribution system components, on the distributor's side of the "ownership demarcation point," using the NPV calculation. This entails the calculation to establish the amounts needed to bring the project NPV ratio to the threshold level of 0. In such calculations, all relevant revenues and costs must be included in the evaluation.

(ii) A listing of the distribution system components that needed upgrade, on the distributor's side of the said demarcation point, including where applicable distribution stations, primary distribution lines, distribution transformers, secondary buses, etc.

(iii) Requirements from all customers for contributions in aid of construction for expansion projects including Large Use customers.

APPENDIX A (continued)
Attachment (1)

Illustrative Examples Of Mapping Activities To Project Evaluation Emphasis

Steps: Hybrid Distribution Projects are untangled into Distinct Activities that are unique along three distinct parameters (see items (i), (ii), (iii) below) leading to the Primary and Secondary Emphasis of Project Evaluation:

Project Driver - establishes the drivers for each project.

Activity Categorization - these are System Expansion, Reinforcement, Replacement, Connection, etc., which provide key links to establish Beneficiaries.

Beneficiary - identifying beneficiary as New versus Existing Customers. In situations where beneficiaries are for both , the capital project costs should either be split by amount of load of each group or the Advancement/Delay of in service date of the facilities should be used to calculate "Incremental Attributable Costs" to the New Load customers.

ACTIVITY		**POSSIBLE SCENARIOS**				
		Project Driver	**Activity Category**	**Who Benefits?**	**Evaluation Primary**	**Secondary**
1	Build Additional Feeder in Existing System Area	Load increase due to new customers	System Expansion	New Customers	Eco Eval	Enhance Eval
		Load increase of existing customers	System Expansion	Existing Customers	Enhance Eval	Eco Eval
		Reliability gains of loop feed options	System Expansion	Existing Customers	Enhance Eval	Eco Eval
2	Replacing Existing O/H Conductors with higher capacity conductors	Load increase due to new customers	Reinforce	New Customers	Eco Eval	Enhance Eval
		Load increase due to existing customers	Reinforce	Existing Customers	Enhance Eval	Eco Eval
		Reduce Losses	Reinforce	Existing	Enhance Eval	Eco Eval
		Meet current Standards	Reinforce	Existing	Enhance Eval	Eco Eval
		Life Cycle Replacement	Replacement	Existing	Enhance Eval	Eco Eval

Activity		Possible Scenarios: Project Driver	Activity Category	Who Benefits?	Evaluation Primary	Secondary
3	Replacing Existing U/G Conductors with higher capacity conductors	Load increase due to new customers	Reinforce	New Customers	Eco Eval	Enhance Eval
		Load increase due to existing customers	Reinforce	Existing Customers	Enhance Eval	Eco Eval
		Reduce Losses	Reinforce	Existing	Enhance Eval	Eco Eval
		Meet Current standards	Reinforce	Existing	Enhance Eval	Eco Eval
		Life cycle Replacement	Replacement	Existing	Enhance Eval	Eco Eval
4	Converting to a higher Voltage on an early asset retirement schedule	Reduce losses	Reinforce	Existing	Enhance Eval	Eco Eval
		Reduce System Operating Costs	Reinforce	Existing	Enhance Eval	Eco Eval
		Lower real estate costs	Reinforce	Existing	Enhance Eval	Eco Eval
5	Installation of automatic switching devices	Decrease in outage time	Reinforce	Existing Customers	Enhance Eval	Eco Eval
6	Installation of a transformer bank	Customer request for connection	Connection	New Customer	Eco Eval	Enhance Eval
7	Installation of U/G Service	Customer request for connection	Connection	New Customer	Eco Eval	Enhance Eval
8	Installation of 2 phases where 1 previously existed	Customer Request for connection	Connection	New Customer	Eco Eval	Enhance Eval
		Increased load due to new customers	Expansion	New Customers	Eco Eval	Enhance Eval
		Increased load due to existing customers	Expansion	Existing Customers	Enhance Eval	Eco Eval
		Reliability gains due to loop feed options	Reinforce	Existing Customers	Enhance Eval	Eco Eval

Activity		Possible Scenarios: Project Driver	Activity Category	Who Benefits?	Evaluation Primary	Secondary
9	Replacement of defective devices i.e. Insulators, (early asset retirement)	Decrease in outage time Safety Concerns	Replace Replace	Existing Customers Existing Customers	Enhance Eval Enhance Eval	Eco Eval Eco Eval
10	Normal Life Cycle replacement of system components	Reliability Meet current standards Safety concerns	Replace Replace Replace	Existing Customers Existing Customers Existing	Enhance Eval Enhance Eval Enhance Eval	Eco Eval Eco Eval Eco Eval
11	Installation of infrastructure for residential and industrial subdivisions	Developer wants inventory of serviced properties	Expansion	Developer	Eco Eval	Enhance Eval
12	Site Specific reliability initiative to bring reliability up to standard	Performance Based Requirement Customer complaint resolution	Reinforce	Existing Specific	Enhance Eval	Eco Eval
13	Site Specific reliability initiative to offer premium standard of reliability	Customer Request	Reinforce	Existing or New Specific Customer	Eco Eval	Enhance Eval
14	Relocation for road widening	Road Allowance Authority request	Replace	Road Allowance Authority	?	

ACTIVITY		**POSSIBLE SCENARIOS**				
		Project Driver	**Activity Category**	**Who Benefits?**	**Evaluation Primary**	**Secondary**
15	Z factor items	?	?	?	?	
16	Build or Expand Transformer or Distribution Station	Lack of Capacity	Expand New Customers	Econ Evaluation Enhance Eval		

APPENDIX B
Common Elements of Discounted Cash Flow (DCF) Model

To achieve consistent business principles for the development of the elements of the financial feasibility test, the following parameters for the DCF approach are to be followed by the distributors. This will standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis.

Common Elements of Discounted Cash Flow (DCF) Calculation

The DCF calculation for individual projects will be based on a set of common elements and related assumptions listed below.

For revenue forecasting, the common elements for any project will be as follows:

(a) Total forecasted customer connections over the Customer Connection Horizon, by class.

(b) A Customer revenue horizon as specified below.

(c) An estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added for connections of various classes of customers, this should be carried out by class.

(d) Customer additions should be reflected in the model for each year of the Customer Connection horizon specified in the document.

(e) Rates derived from the existing rate schedules for the particular distributor reflecting the distribution (wires only) rates.

For capital costs, the common elements will be as follows:

(a) An estimate of all capital costs directly associated with the connection of the forecast customer additions.

(b) For connections to the distribution system, costs of the following elements, where applicable, should be included: distribution stations; distribution lines; distribution transformers; secondary busses; services; land and land rights. Note that the

"Ownership Demarcation Point" as specified in the Distribution System Code would define the point of separation between customers' facilities and a distributor's facilities.

(c) An estimate of incremental overheads applicable to distribution system expansion.

For <u>expense forecasting</u>, the common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures: the incremental attributable costs directly associated with the connection of new customers to the system will be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

<u>Specific Parameters/Assumptions</u>

Specific parameters of the common elements include the following:

(a) A maximum customer connection horizon of five years will be utilized. For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board.

(b) A maximum customer revenue horizon of twenty five years will be used. It will be calculated from the in service date of the new customers. This means, for example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

(c) A discount rate equal to the incremental after-tax cost of capital: this is based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

(d) Discounting reflecting the true timing of expenditures: up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, and operating and maintenance expenditures. Note that for certain projects, Capital Expenditures may be staged and can occur in any year of the five year Connection Horizon.

(e) Wires only charges: distribution specific revenue is to be calculated based on distribution (wires only) rates.

APPENDIX B (continued)

Discounted Cash Flow Methodology

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net(Wires) Operating Cash	=	*(Annual(Wires) Revenues - Annual (Wires) O&M)*
Annual (Wires) Revenue	=	*Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]*
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	*Municipal Tax Rate * (Total Capital Cost)*
Total Capital Cost	=	*(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)*
Annual Capital Taxes	=	
Annual Capital Tax	=	*(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax ? Annual Capital Tax)*

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital	=	P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level). This applies for implicated system elements at the utility side of the ?Ownership Demarcation Line?.

Note: Above is discounted to the beginning of year one over the customer addition horizon.

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $\dfrac{\text{[(IncomeTax Rate) * (CCA Rate) * Annual Total Capital]}}{\text{(CCA Rate + Discount Rate)}}$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ? year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

2.11 METHODS FOR ADDRESSING A PROJECTED SHORTFALL IN ECONOMIC FEASIBILITY IN A DISTRIBUTION SYSTEM EXPANSION

[FINALIZED: FEBRUARY 22, 2000]

Issue Statement

A separate Summary of Recommendation dealt with the methodology for performing an economic evaluation of distribution system expansion projects and the approach that should be used to determine capital contribution from a customer or a developer. The issues are:

> What options are available to a distributor in dealing with a projected shortfall as determined by the economic evaluation of a prospective expansion project?
>
> Of these options, what treatment of the collection of contributed capital should be prescribed and what should be at the discretion of the distributor?

Assumptions

1. A shortfall is calculated using the net present value economic analysis approach recommended in the *Economic Evaluation Model for Distribution System Expansion* summary of recommendations (SoR - Economics).

2. Connection costs are addressed in the *Connection and Service Upgrade Costs* summary of recommendations (SoR - Connections).

3. Enhancement costs are addressed in the *Enhancement Evaluation Model* summary of recommendations (SoR -Enhancement).

Options

1. Distributors should be obligated to charge beneficiaries (customers) 100% of the shortfall in a project's economic feasibility; that is, to collect an amount which brings the projected NPV of the project to $0.00.

2. Distributors should be obligated to collect capital contributions by a prescribed range as specified in the DSC.

3. Distributors should have full discretion to collect 0 to 100% of the shortfall as capital contributions, *by consistent policy*.

4. Distributors should have full discretion to collect 0 to 100% of the shortfall as capital contributions, *by project.*

Background Information

Contributed Capital, known also as capital contributions or contributions in aid of construction, are payments by customers in order to pay for the cost of connecting them to the electrical distribution system. For newly constructed residential or commercial and industrial facilities, these payments have sometimes been collected by municipalities on behalf of the electrical utilities in the form of development charges. In addition to development charges, some utilities raise additional funds by entering into contractual arrangements with developers (known as Electrical Distribution Agreements, or EDAs). In some areas, EDAs recover the direct costs associated with connecting the customer to the distribution system (i.e., underground distribution system on the customer's property, or poles and conductor to connect an industrial customer located some distance from existing distribution system) whereas the development charges recover off-site costs associated with connecting new customers, such as enhancement of the distribution system to carry the increased load, etc.

While development charges have been used in the past,[6] it should be noted that as Municipal Electric Utilities (MEUs) convert to corporations incorporated under the Ontario Business Corporations Act, neither the incorporated electric utilities nor the municipalities will be permitted to collect development charges on behalf of the incorporated electric utility.[7]

Accounting Treatment

Beginning in the 1960s, contributed capital began to be used to finance the capital costs of expansion in some jurisdictions, particularly when customers in newly developing subdivisions wanted underground electrical service rather than overhead wires and poles. It was thought that the extra cost of constructing the underground distribution system should be borne directly by the customers receiving the aesthetic value accorded by the absence of poles and overhead wires. The cost differential was incorporated into a lot charge levied on the properties to receive this service. Existing customers' rates were unaffected as the new customers paid separately for the enhanced service. In effect, the price of electricity infrastructure was buried in the cost of the real estate. The developer purchased assets necessary to provide the underground service and transferred the assets to the local MEU when the subdivision was assumed by the Municipality.

[6] Development charges are collected by municipalities under the authority of *The Development Charges Act, 1997.*

[7] Part XI of *The Electricity Act, 1998* requires the MEUs to become incorporated under the Business Corporations Act no later than the second anniversary after s.142 comes into force. S.148(3) prohibits development charges under *Development Charges Act* on behalf of the incorporated electric utility.

Initially, contributed capital was not included in the rate base[8] and MEUs did not earn a rate of return on contributed capital. As reported by the Distribution Rates Task Force,[9] MEUs generally had no difficulty with the concept of contributed capital being excluded from the rate base as their rate of returns were well below the maximum allowed by Ontario Hydro. However, as suburban development accelerated in the 1980s, some utilities began to experience sustained growth and started to overtake their rate of return limit. In addition, some high growth utilities had begun to rely heavily on contributed capital as a source of financing for fixed asset additions.

As a result of this environment, Ontario Hydro undertook a review, in consultation with the Municipal Electric Association. The review indicated that excluding contributed capital from the rate base and excluding depreciation associated with these assets from operating costs caused difficulty for some MEUs. Utilities with a high proportion of contributed capital were having difficulty generating sufficient funds from operations for normal reinvestment requirements of the utility. In 1994, Ontario Hydro approved a change in the accounting treatment of contributed capital and allowed the inclusion of net fixed assets financed by contributed capital in the rate base used to calculate the maximum allowable rate of return and allowing the corresponding depreciation to be charged to operating costs.

The *Accounting Procedures Handbook* issued by the Board, states:

> To harmonize the regulatory treatment of contributions in aid of construction for electric utilities with that of gas utilities, capital assets funded through contributions in aid of construction and any related amortization expense will not be allowed to be included in the electric utility's rate base and revenue requirement, respectively.[10]

The PBR Rate Handbook decision of January 18, 2000, states that future capital contributed on or after January 1, 2000 will not be included in rate base.

Contributed Capital in Cost-of-Service Regulated Gas Utilities

Historically, lack of uniformity in gas utility capital contribution policy and practice was problematic. The Board wanted a uniform and fair methodology for the utilities to apply to their expansion projects, and the utilities wanted flexibility to expand without having each project scrutinized by the Board for approval. The result was Board Report EBO 188 (January 30, 1998)

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8 The rate base is the asset base upon which the utility is allowed to earn a rate of return.

9 *Report of the Ontario Energy Board Performance-Based Regulation Distribution Rates Task Force*, May 18, 1999.

10 *Ontario Energy Board Accounting Procedures Handbook For Electric Distribution Utilities*, effective January, 2000, Article 430.

which provides a common methodology for calculating economic feasibility of gas distribution expansion projects. Gas distributors are allowed to maintain a “rolling project portfolio” of expansion projects that must maintain a minimum Profitability Index (PI)[11] of 1.1. Within a portfolio, individual profitability may vary. All projects must achieve a minimum threshold PI of 0.8 for inclusion in a utility’s portfolio and projects that do not meet this criteria can use a capital contribution to raise it to a PI of 0.8.

In the Report, the Board directed the gas utilities to:

> prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:
>
> the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total excess service line fees and other charges.[12]

Summary of Discussion

In deliberating on why a distributor might be motivated to make up NPV shortfalls through customer contributions, the group considered the following:

Financial viability of the distributor should not be threatened. The business of electricity distribution is a monopoly, not a charity. The distributor should not be exposed to undue risk from customer or shareholder.

Freedom for distributor's to manage their business (as contemplated within the PBR framework). Under PBR, a distributor will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.

Provision of non-discriminatory access to the distribution system. Non-discriminatory access is a licence condition for distributors. Economic efficiency hinges on non-discriminatory access. Incorrectly structured charges may contribute to inefficient use of resources. A related element is contestability in carrying out some capital works to ensure that customers are charged the lowest possible cost for their connection to the distribution system.

Minimal Cross-Subsidization. Existing customers’ rates should not be affected as a result of costs

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11 As per E.B.O. 188, Profitability Index (PI) =

12 E.B.O. 188, January 30, 1998, 4.3.3, p. 19.

associated with adding new customers. That is, existing customers' rates should not increase as a result of new connections; nor should they be lower than they would otherwise be as a result of growth in the number of connections.

Uniformity of approach across electricity distributors in the province is desirable. Uniformity of policy approach should remove anomalies between distributors so that customers are not faced with uncertainty and various practices. A uniform capital contributions policy means that the method by which the capital contributions are determined is consistent between distributors, it does not mean, however, that the level of capital contributions charges in different distribution areas should be the same, as the different cost structures and tariff levels of the distributors need to be taken into account.

Standard practices around customer connection and contribution policies have been mandated by the Board in the gas industry.[13] However, among those utilities that require capital contribution, there is no consistency around level of contribution or when to ask for contribution. In electricity, this kind of diversity may not have been a big concern in the past because the service provider was a public utility whose shareholders were the ratepayers. Consequently, concerns may have been mitigated somewhat by the knowledge that the utility operated with a very low rate of return and any returns were reinvested into the system to the benefit of the ratepayer. With the conversion of MEUs to corporations that may be owned by private investors, greater transparency in utility practices with respect to capital contributions may be needed to ensure the public interest is being maintained.

Elaboration of Options

An important assumption emerged out of the group's deliberations:

The shortfall is attributable to the customers in the forecast and will be collected from them proportionately based on the same cost allocation methodology used in the economic evaluation model that determined the shortfall in the first place.

Under Option 1, it would be mandatory to collect customer contributions. Once the amount was calculated, the offer to connect would include this amount in it. This option offers the purest "user-pay" method that ensures existing customers will not subsidize new customers. Collecting capital contribution provides customers with non-discriminatory access to the distribution system by making it easy for them to test the fairness and reasonableness of the offer. It protects the distributor from uneconomic investment pressures from its shareholders, and provides the most transparent pricing signal to the market. However, this option offers the distributor the least

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[13] This is a result of Board order E.B.O. 188, "*...Matters Relating To Natural Gas System Expansion*", 30 January 1998, as well as the fact that there are only three gas distributors as compared to over 200 MEUs.

flexibility to manage its business as contemplated within the risk-return pay-back opportunities under a PBR regime.

In Option 2, there is discretion, but it is in someway restricted. This option relies on the Code to specify that only certain expansion projects could go ahead (i.e., where the combination of capital contribution and the return on the project bring the NPV to a specified level). For example, there could be a profitability hurdle similar to the 0.8 profitability hurdle established in EBO 188 for the gas utilities. That is, the gas utilities cannot invest in projects if the PI is less than 0.8, so they have the option to collect capital contributions to bring the PI up to 0.8. The project may proceed, but is considered an un-economic investment because the PI is less than 1.0. Consequently, the intent of Option 2 would be to “protect the distributors from themselves” and support “rational expansion of the distribution systems.” This option is more prescriptive than Options 3 and 4, since it would restrict the distributors from investing excessively in uneconomic expansions, at the shareholder’s risk. However, it still affords some freedom in management decision-making. In a PBR environment, one might argue that if a distributor wants to invest in what looks to be an uneconomic project, they should be allowed to, providing existing rate-payers are “kept whole.”

From a code perspective, Options 3 and 4 are very broad. The group acknowledged that where utility discretion is high, there is opportunity for “customer contributions gaming” on competing boundary projects. In this situation, a customer may be courted by distributors competing on the basis of capital contributions at the shareholders’ risk. This likely would come before the OEB, and the OEB would likely have to rule.

In Options 3 and 4, any remaining shortfall beyond that collected from customers would be at the shareholder’s risk. These shareholder invested funds would come from retained earnings. It was pointed out that under a PBR regime, these distributor investment choices (i.e., deployment of retained earnings) would not form a justifiable basis for revenue requirement review (analogous to the rate case in a cost-of-service regulatory environment).

In Option 3, the distributor's Conditions of Service would contain the distributor's capital contribution policy. The group felt that distributor policy design should consider customer class. For example, the Conditions of Service could stipulate that on industrial projects, the distributor will always pay x% of the shortfall, and on residential projects, the distributor will always pay z% of the shortfall. Concern was expressed that this kind of policy may compromise non-discriminatory access. However, this option does offer the customer much more transparency than Option 4 - the customer can see the distributor’s policy clearly in the Conditions of Service.

The concept of customer equity was discussed as entailing a sense of fair treatment as well as equal treatment for those in similar circumstances. The obligation for “consistent contribution policy across all projects within the utility’s service area that is available for public scrutiny” may somewhat mitigate customer equity concerns. A distributor's discretion will still have the power to send artificial price signals regarding distribution system expansion to the market. This may not promote informed investment decision-making for customers because the customer needs to have comparable and advance knowledge of the cost and requirements of the distribution services they are requesting in order to make informed investment decisions.

The group quickly discounted Option #4 because it was the least transparent, and may be seen to compromise the provision of non-discriminatory access by giving the distributor too much discretion. This option would make it very difficult for a customer to assess the fairness and reasonableness of an offer to connect. It would materially hinder contestability and potential for market efficiencies by masking anomalies between distributors. As the provision of infrastructure and connection to the grid are monopoly activities, a capital contributions policy should be open to public scrutiny and it should be able to explain to the community why a capital contribution is necessary and how the level of payment was arrived at.

Key Implementation Considerations

Collection Horizon

Based on a connection horizon of 5 years, over what period can the distributor collect the specified capital contribution?

With respect to the comparison between the connection horizon and the collection horizon in the gas industry, they usually are the same. However, it is at the discretion of the gas utilities as to whether they collect the shortfall “up front” or “over time”, and there may be differences between projects as well. In a developer situation, the utility may want to collect any shortfall “up front”, so the time horizon of the collection period is not relevant. In this case, the distributor’s customer is the developer, and how the developer passes through this cost to consumers is the developer’s business.

Customer Demarcation Point (Ownership)

As recorded in SOR-Economics, it was agreed that distributors will be expected to follow the DSC to identify the customer demarcation point (ownership). Also, policy regarding contribution in aid of construction will be premised on the customer demarcation point (ownership).

Harmonization of Policies

In gas, the Board found it problematic that the three gas distributors in different regions of the province had differing contribution requirements. The Board directed the gas utilities to develop and maintain common contribution and connection policies (subject to Board approval) which outline how charges are derived.

To date, consistent practices have not been achieved between the gas utilities. Consequently, the group questioned whether we should strive for consistency, or allow some discretion.

Symmetry with Gas Distributors

Although the treatment of contributed capital in cost-of-service regulated gas utilities is noted, the group discussed how it may not apply to electricity projects. Examination of the rolling portfolio approach to electrical distribution system expansion is addressed in the SOR - Economics. The portfolio approach employed in gas assumes that utilities decide where to serve. The portfolio was intended to balance high and low profitability projects so as to help decide which areas should be served. The electricity provider has an obligation to make an offer to connect all customers within their service area.[14]

Risk Management

Performance-Based Decisions

There was a concern expressed by group members that under the new PBR framework, shareholder pressure on the LDC may be high to minimize contributions to maximize rate base. Under PBR:

- The goal of capital investment is to maximize return and maintain service quality.
- Capital investment costs do not directly impact distribution rates because the price that the utility charges for its service is decoupled from its cost. In Ontario's proposed PBR framework, re-basing to adjust a utility's revenue requirement and consequently its distribution rate, is uncertain.
- Capital investments impact on utility productivity. For example, assuming adherence to quality performance measures, utility productivity statistics improve when output increases (due to growth) more than input, or where output remains level and input declines (due to productivity improvements).
- Increased utility productivity delivers increased opportunity to earn returns.

Rebasing of rates was discussed by the group as a possibility in the 2nd generation of PBR. It was decided that although this is a possibility that distributors may choose to consider in their investment decision-making activities, the uncertainty of this happening suggests that our recommendations should be neutral with regard to whether or not rebasing occurs.

[14] DSC Summary of Recommendation on the Economic Evaluation Model (SOR - Economics)

The decision on the accounting treatment of contributed capital going forward (i.e., will not earn the rate of return) was discussed. It was discussed how the NPV approach to determining the amount of contributed capital required on any given project actually tempers the full effect of no return on contributed capital because it includes distributor rate-funded investment capabilities.

The question of how much 'socio-economic' policy considerations should be put into the DSC, as opposed to letting the business drivers operate freely, was discussed. Under PBR, a distributor will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.

Forecasting Risk

As identified in the SOR-Economics, forecasting inaccuracies are a major concern for distributors. In sub-division growth, the distributor relies on the developer’s connection forecast. In rural and remote territories, particularly those involving line extensions to individual customers, it is impossible to accurately forecast the number of customers that are likely to actually connect to the extension during the 5-year connection horizon period. Yet, inaccurate forecasts can have a significant impact on both the distributor and the customer(s) requesting connection.

At the same time, it was recognized by the group that there will always be forecasting discretion. The group discussed how the economic evaluation model inputs might be scrutinized since there is relatively high discretion on the model inputs. The group conceded that any forecasting bias should be tempered by third-party right to challenge the forecasts.

Rebate Concept

The group revisited the concept of a rebate policy to help mitigate forecasting risk to the distributor and provide fairness for the customer. For example, where determined shortfall is high and a single customer is hit with a large capital contribution, the use of a rebate program may help the customer assess the fairness and reasonableness of the offer when the customer has the prospect of receiving a partial rebate sometime in the future. Concern was expressed that the existence of an unconstrained re-bate program may encourage distributors to under-forecast. This led to the question: “when is a rebate program appropriate?”

As discussed in the SOR-Economics, in rural and remote situations, to handle these types of situations in the past, some distributors had developed a "rebate policy" approach, administered as a 5-year quasi-insurance agreement for which a small administration fee was charged. The group proposed that the approach presented in Appendix A to this document may be adopted by distributors where forecasting risk is high. If adopted, the rebate policy and methodology would need to be documented in the distributor's Conditions of Service.

Dealing with "Shortfalls on the Shortfall"

Beyond the 5-year connection horizon, a situation may occur where a distributor may not have collected the required capital contribution. In this instance, the group agreed that the distributor should be able to apply to the OEB to collect the remaining shortfall from new customers connecting beyond the 5-year horizon.

Implementation Issues

There was some discussion around the cost of the design work and whether this should be included in the economic evaluation to be included in capital contributions. It was noted that customers should be able to go elsewhere to get this work done (contestability), and the other issue was whether the design costs should be included in the total cost of the project (and thus part of the Capital Contribution calculation). The design work is part of the process of adding facilities, but the question is whether this should be part of the capital, or a 'fee for services rendered'. The different treatment of the capitalization of design has historically been a function of whether or not utilities built the facility. It was noted that these costs might not be too material. If someone else generates the design, these costs would not be part of the economic feasibility, but the costs of the review of the design might be. The group noted that this might be identified as an 'implementation issue'. The group noted that this might be identified in the SOR-Connections.

Collecting customer contributions: This SOR addressed how much of an NPV shortfall may be collected as capital contributions. It does not address how capital contributions will be collected from customers. Will distributors develop individual policies on collection of capital contribution? Will these policies be documented in the Conditions of Service?

Recommendation

Given that the shortfall is attributable to the customers in the forecast and will be collected from them proportionately based on the same cost allocation methodology used in the economic evaluation model that determined the shortfall in the first place, Option 3 is recommended.

1. Distributors should have full discretion to collect 0 to 100% of the shortfall as capital contributions, *by consistent policy*.

2. The contribution policy must be uniformly designed by customer class across all distributors and documented in the distributor's Conditions of Service.

3. A separate, but related recommendation is also proposed that a rebate policy, as outlined in Appendix A, should be offered to customers where distributor forecasting confidence is low. There would be no administration fee during the 5-year connection horizon, but

would be optional with an administration fee beyond the 5-year connection horizon.

Voter Summary

Unanimous.

Dissenting Opinions

None.

APPENDIX A

The Rebate Program:
When might rebate programs be appropriate?

Consider, for example, a hunting camp in northern Ontario requesting a line extension requiring a $100,000 capital contribution. There is no forecast for any other customers that might wish to also use this line during the 5-year connection horizon so the hunting camp is required to pay the full $100,000. In year 3, a competitor recognizes a potential opportunity and purchases property along the line to build a hunting camp of his own. The Distributor must connect this new customer but could not collect any capital contribution since the line has already been completely paid for. The result of inaccurate forecasting in this case is the inequitable allocation of capital contribution between the two customers. If, on the other hand, the Distributor had initially forecast two hunting camps connecting during the 5-year connection horizon but only one materialized then the Distributor would have collected only half of the required capital contribution leaving the shareholder and /or other Utility customers at risk. This type of scenario can also arise in sub-division developments.

To address these concerns under the new expansions policy it is necessary to develop an approach that would encourage Distributors to forecast as best they can but still allow for a rebate policy to address customer inequities when they occur. The following is proposed:

1. Distributors would be required to forecast new connections over the 5-year connection horizon as accurately as possible.

2. During the 5-year connection horizon, the Distributor would collect capital contributions up to the forecasted number of customers + or - some % (say 10%). If more customers than forecasted wish to connect, the Distributor would continue to collect capital contributions but would be obliged to implement a rebate equivalent to the over collection. This rebate would be paid to all customers who connected and paid capital contributions already within the 5-year connection horizon. No administration fee would be charged by the Distributor.

3. If the Customer wishes to continue to protect his investment for an additional 5-year period in hope of receiving some additional payback for his initial investment, the Distributor should be allowed to offer such a service to the customer(s) at a mutually negotiated fee (administrative charge).

This proposal would encourage distributors to forecast as accurately as possible because they would be penalized if their forecast was inaccurate by more than a specified % (say + or - 10%) by virtue of having to implement a rebate or apply to the OEB to collect beyond the 5-year connection horizon. It would also provide for a more equitable allocation of capital contributions across actual beneficiaries.

There is concern by the largest rural distributor in Ontario that implementation of such an approach on a per-project basis would require a significantly high effort level. A more simplified approach might deal with all expected additional customers over a one-year period and calculate, ahead of implementation, a uniform "Capital Contribution" amount. However, the sub-group has recommended in the SOR-Economics that the “individual project based evaluation approach is recommended, to match customers to associated expansion costs and possible capital contribution requirements.”

2.12 CONTESTABILITY OF CONSTRUCTION WORK PERFORMED BY A DISTRIBUTOR

[FINALIZED: MARCH 17, 2000]

Issue Statement

In another Summary of Recommendation on the Economic Evaluation Model for Distribution System Expansion, it was recognized that if a capital contribution were required from a customer towards a project, the customer would want to be assured that the costs presented are fair and reasonable. The issue is:

> What should be considered contestable work in which a customer can request competitive pricing from other than the distributor and what should be the process for initiating or handling such requests?

Options

1. The DSC should not include any reference to contestable work and let customer pressure, market forces and the discretion of a distributor determine fair and reasonable pricing.

2. The DSC should prescribe what work by a distributor would be considered contestable.

3. The DSC should prescribe what work by a distributor would be considered contestable where:

    a. a capital contribution is required from a customer, and where

    b. the percent of project where a contribution is required is greater than 50% of total project cost.

Background Information

Historically, the work completed by distributors has employed a variety of internal and external resources. Distributors generally have developed their own Engineering Departments to plan and design new construction as well as research construction standards, material standards and new technologies. Distributors have Line Crews that perform new construction projects, distribution system maintenance and generally are the staff that is on call for handling distribution system outages and repairs.

Some distributors have their staff perform all of their line construction and maintenance activity, while others contract out some line construction work, various aspects of their maintenance work, civil work in subdivisions, and non-core activities such as tree-trimming and landscape restoration.

Section 13.2 of the Distribution Licence states that the licence shall make an offer to connect a building to its distribution system. Section 13.4 of the Distribution Licence further states that any question as to the fairness or reasonableness of the terms of an offer to connect shall be determined by the Board.

Summary of Discussion

There are several sub-issues to the question of contestability of work and the discussion has been divided into the main components.

The first issue appears to be how much of a distributor's work should be considered as contestable. Is only the provision of labour, material, and equipment, i.e. the cost of construction, open to competitive pricing? Should the Planning and Engineering functions be routinely contestable? The majority of the members felt that a distributor must have the ability to operate their business on a certain level of core activities that they can plan on and staff for appropriately. Effective distribution System Planning will be very important to minimize losses and expand a system in a well-planned, cost-effective manner. Distributors should be able to choose if that function is performed internally or outsource, rather than have that as a function of a customer's choice. Effective system planning affects the operations of the wires business and all the existing customers to an extent that this work should not be contestable.

Tendering of Construction Work

The choice to tender out construction work or to perform the work with internal construction crews is a practice that varies widely across utilities. The most commonly tendered work is the civil work involved in trenching, installing ducts, manholes, and cables. This work generally is done in joint use trenching, involving telecommunications and cable TV companies as joint use partners to reduce the construction costs by sharing common costs. The distributor may act as the prime constructor and is responsible for overall coordination of the civil contractor, as well as inspection of the installation of their own plant.

Overhead line work is tendered out by fewer utilities than underground construction. This is especially the case where the construction work involves handling live circuits that are supplying existing customers. There appears to be two main reasons for this; first, some distributors are concerned that the contractor may not have the qualified staff nor the appropriate equipment to perform the work; and second, some distributors do not prepare sufficiently detailed drawings and work descriptions for overhead work to obtain appropriate and equivalent bids for the work to be done. The discussion regarding contractors also raised a concern, that tendering of line construction work would not be on a level playing field for utility construction crews if the customer were able to get pricing from anyone they desired. This may lead to unqualified firms performing the work with less than acceptable equipment and work standards.

Ontario has several Line Construction Contractors that have qualified staff, good equipment, and the appropriate work methods to perform all types of Line Construction work. Several years ago, the MEA, E&USA and the ECAO (Electrical Contractors Association of Ontario) prepared a guide titled "Utility Tendering Practices Guideline." The guide was developed to provide recommended procedures and language for calling bids to ensure that fully qualified contractors submitted properly prepared bids. The question of "due diligence" and the relationship between the Constructor (e.g. the distributor) and the Contractor was addressed to provide a process for completing projects safely and successfully. Guidelines such as these can be used to pre-qualify contractors for prospective work. Some of the key points of pre-qualifying a Contractor are in Appendix A. In regards to providing sufficient and appropriate documentation for tenders, the utilities would need to spend more time (and expense) preparing bid documents.

Construction work that is released to internal Line Construction Crews, generally requires less description and instruction than if the work is going out to tender. This is the result of Line Construction Crews and Engineering Staff discussing and planning jobs together, which develops an understanding of project needs and construction techniques. To enable a customer to request competitive bidding for a project, the distributor will need to ensure that drawings, design details and equipment schedules are complete to avoid any errors that internally may be picked up in the course of normal "as built" construction changes, however, externally any revisions may result in extra costs to the tendered price. A complete set of bid documents should include in addition to the drawings:

- Instructions to bidders
- Bid Form
- Contract Agreement and general conditions
- Any supplementary or site-specific conditions
- Specifications and construction standards
- Any scheduling requirements

If the distributor prepares these documents, then the customer should be charged the extra expense that is incurred, by the distributor, to obtain competitive bids. If the customer is responsible to administer the bid process, the distributor should be allowed to recover expenses incurred to provide any bid documents beyond normal drawings required for construction by the utility Line Construction crews. The customer would also have to take on the liabilities of being the Constructor of the project in the eyes of the Ministry of Labour. In addition, if the project is sufficiently large, the utility and the customer should ask for a form of security performance or surety bonding from the contractor.

Once the contract is awarded to the contractor, the distributor may need to perform switching to isolate sections of the distribution system for work to proceed. The distributor will also require inspection of the work that is done. These are also costs that need to be reimbursed to the distributor by the customer.

When Should a Customer be allowed to Request Competitive Bidding

There was much discussion over when a customer should be able to request competitive bids. In one jurisdiction (Australia), the distributor has an established dollar value over which the customer is entitled to request competitive bids. In another jurisdiction (SDGE in California), the customer has the option to obtain competitive bids balanced against a unit price for construction from the utility.

In the Final Report to the Ontario Market Design Committee, the Retail Technical Panel dealt mainly with issues around retailers, consumer education, and marketing practices when they were referring to consumer protection. Customer choice would imply that providing the distribution wires service is a competitive service, however a distribution service is a regulated monopoly service within a service area. Thus there is the dilemma of providing the appropriate mechanism for customers to obtain a fair and reasonable offer to connect to a distribution system without forcing a distributor to give up a core activity of running a wires business, such as distribution system construction.

In the past, Commissioners that were elected or appointed to the Commissions of Municipal Electric Utilities (MEUs), were not only acting as a Board of Directors, they were also the customer's voice in MEU policies. Most customers were generally willing to accept the Direction of the local electric utility and would ask for a breakdown of any required financial contributions when asking for connection of service. Some customers (generally larger ones) and some developers questioned the exclusive right of construction of utilities, and brought their concerns to the Commissioners or Senior Management of the utilities. This has led to varying practices where some utilities have allowed design of distribution systems in subdivisions by others and many utilities allowed for the developer to install the subdivision and in some cases also provide the materials. Most utilities allow for competitive bidding in civil installation work.

Option 1 is viable if PBR works correctly and provides incentives to distributors to continually reduce costs and improve productivity. The pressure to reduce costs should force distributors to have appropriate staff for the work to be done, rather than have staff on salary that is there waiting for any work that may come up. PBR should also force utilities to staff for their core business activities and to outsource functions that are less expensive to outsource than to do with their own staff. As indicated earlier, many utilities already outsource civil construction work and installation of underground cables, installation of streetlight poles, and landscape restoration. In recent years, more utilities are outsourcing tree-trimming programs, some of the line construction work during peak construction periods and other work such as vacuum excavation for pole installations.

It was also pointed out that the Uniform System of Accounts should force distributors towards more uniform accounting practices. This will allow the comparison of expenses between distributors and should drive distributors with higher expenses to find ways to reduce their costs.

One could arguethat the effects of PBR, comparisons through the Uniform System of Accounts and the unbundling of utilities into "Wires Companies" should ensure that customers are receiving fair and reasonable offers for expansion work. The last key to accepting Option 1 as viable is that customers do have the ability to bring a complaint before the OEB if the customer believes that the offer is not fair and reasonable.

With the "unbundling" of the electricity distribution business in Ontario, some members of the group suggested that customers may not continue to accept the policies of the distributor, without options, put forward by their distributor. This may result in a change in consumer buying behavior and that customers may want options in their ability to influence pricing of offers to connect.

One approach to recognizing this change in consumer buying behavior could be to allow independent contractors, including the Competitive Affiliates of other Distributors, to bid on work projects related to adding or modifying distribution electric plant where customers are asked for a financial contribution. However, the group was not prepared to introduce a process that would allow contractors or others who are not qualified, to work on the distribution network.

It is the distributor's responsibility to protect the integrity of the distribution system and the reliability of supply to existing and future customers. The DSC must balance the rights of existing and future customers against the perception that all construction work where a financial contribution is expected from the customer, must be open to competitive bidding to obtain a fair and reasonable offer for the customer. Some members felt comfortable in allowing competitive bidding and construction on all work that was not currently connected to their system, such as new subdivisions or new line extensions. Most members were of the opinion that work in and around existing live circuits was one of the core activities of distributors, which requires certain staff, vehicles and equipment for operations and maintenance activities as well as system trouble activities. These same staff, vehicles and equipment are required for live circuit construction activities and distributors should be allowed to continue to spread the cost of specialized vehicles and equipment across more than just maintenance activities.

Consideration for Collective Agreements

Another aspect to consider is what jurisdiction the DSC has over Collective Agreements. It would appear that the DSC cannot take precedence over clauses in Collective Agreements between distributors and their unions. Some Collective Agreements have clauses that restrict contracting out work or that will not allow work to be contracted out that will result in the lay-off of unionized employees. The recommendation should consider potential impact in this regard.

Obligations to Competitive Bidding

Some members of the group felt that Option 2 was more appropriate and that distributors should have some form of options open to customers when they are required to make financial contributions. Under Option 2 it should be the distributor's responsibility to inform the customer, they have a choice of constructor, when a financial contribution is required, on an appropriate project. It should be the responsibility of the distributor to have a list of pre-qualified contractors available to customers for use in this circumstance. The rules and process to become an approved contractor, on the pre-qualified list, is the responsibility of the individual distributor.

One member suggested a central body could be used to review large contractors and through this mechanism be seen as a contractor on all distributor pre-qualified contractor lists. The value to a broader review process was to achieve administrative efficiency in the review process and ensure fair access to all distributor lists for contractors. The organization suggested to perform the province wide review was the Electrical Safety Authority. While on the surface the idea of reducing administrative processes around the qualification process had some merit, it was not supported as each distributor must perform their own due diligence in checking the qualifications and safe work practices of a contractor. It was also noted that if a central body were to approve a contractor for use by all distributors, that same process would have to revoke approval of the use of a contractor by all distributors, if one distributor had complaints or concerns in dealing with the contractor. The idea of a central registry to form province wide pre-approved lists was rejected as not supporting individual distributor due diligence.

On the subject of fair access to a distributor's list, the group discussed whether the contractor would have access to OEB complaint processes if the contractor were excluded from one distributor's pre-qualified contractor list. This avenue of complaint was not seen as within the scope of the OEB mandate. Contractors would be left to appeal to the distributor's Boards if they were excluded. The group discussion concluded, if a customer wanted a specific contractor used, and this contractor was not on the pre-qualified contractor list of that distributor, the customer would not be able to demand the use of the specific contractor. The distributor's obligation is to have a fair and reasonable list of pre-qualified contractors in their service territory.

Most distributors have construction design and material standards used in their distribution system. These standards are recognized as a valuable asset of the distributor. If a contractor is interested in becoming pre-qualified for the work under this SOR then, they should recognize the need for them to purchase these standards from the distributor. This process of having the design and material standards, in the hands of pre-qualified contractors, may assist the distributor in establishing the framework against which others may perform work activities. Through the sale of the standards, this becomes a revenue approach for the distributor shareholders. The construction and design standards will be the benchmark used by the distributor in accepting the distribution network as constructed by others before it is accepted and commissioned.

The distributor may decide, for example, that the standard in their service territory for construction by others includes material purchased by the contractor from the distributor. The distributor would then be able to ensure material standards are followed without a significant administrative burden. This approach would support a revenue approach to the supply of materials used in the service territory accomplished through the pricing of materials.

In all cases, the distributor reserves the right to inspect and approve all aspects of the constructed facilities part of a system commissioning activity. A concern was also raised that a customer may force a distributor to time and expense of competitive bidding when the customer's contribution to shortfall may be less than 1% of the value of the job ($2,000 on a $250,000 expansion).

If competitive bidding is selected, it should be the customer's responsibility to decide if they want parties, other than their local distributor, to provide estimates of cost or to construct the required facilities, to using bids, from individuals from the pre-qualified contractor list. To ensure that the distributor is not at risk as the Constructor of the project, there are several aspects that a customer must be responsible for performing. It should be the customer's responsibility to contact pre-qualified contractors to request bids or to hire the distributor to do this activity at a "fee for service". It should be the responsibility of the customer to notify the distributor, within the project time line described by the Utility, of the successful contractor or the approval by the customer to have the distributor do the construction. The proposed price by the contractor should include all of their costs to construct including materials, labour, commissioning costs, etc. The distributor should not be required to bill or collect any of the costs related to the construction project where a customer chooses to award the contract to someone other than the local distributor. This will require the customer to ensure that the project is complete and that any loose ends will not be the responsibility of the distributor. The distributor should not be held liable for any financial arrangement between the customer and the contractor. The customer will be responsible to pay any engineering and inspection costs incurred by the utility due to the tendering process and construction by the outside contractor. The customer must also pay for any line construction work required by the distributor's staff to energize the project. The cost to the customer to compare against the utility construction costs will be the proposed price by the contractor, plus the distributors costs for engineering, inspection, and line construction work. The distributor will re-calculate the NPV shortfall the Economic Evaluation Model for Distribution System expansion using the total cost noted above. The distributor will rebate the customer the difference between the costs paid to the contractor and the shortfall from the NPV calculation.

Recommendation

The group could not endorse Option 3 as it could lead to eroding the viability of the core activities of distributors to the detriment of existing customers.

Option 1 is the preferred option and the DSC should not include any reference to contestable work and let customer pressure, market forces and the discretion of the Distributor determine fair and reasonable pricing. The DSC Task Force is of the opinion that outsourcing is a common practice with some utilities and that PBR will force all utilities to look at outsourcing to reduce costs.

Option 2 is recommended in a modified format. The DSC should prescribe that a fair and reasonable offer should be made to construct facilities to connect a customer to a distribution system. The distributor should follow these principles:

- Costs should be unbundled to allow the customer to clearly see costs for Engineering Design, Materials, Labour, Equipment, and Administrative activities

- Customers should have a choice to obtain competitive bids from qualified contractors under the following conditions:
  - The project requires a capital contribution from the customer.

And - The construction work does not involve working with existing circuits.

And - The work by a contractor does not contravene the Collective Agreement in effect with the Distributor and unionized employees of the Distributor.

In regards to the customer electing to obtain competitive bids, some key principles should be followed:

- Distributors should have the responsibility to inform the customer they have a choice of constructor.

- Distributors should have a list of pre-qualified contractors available to customers for use in this circumstance.

- Distributors should provide the rules and process to become an approved contractor and is the responsibility of the individual Distributor.

- Distributors reserve the right to inspect and approve all aspects of the constructed facilities as part of a system commissioning activity, prior to connecting the constructed facilities to the existing distribution system.

- Customers should have the responsibility to decide if they want to use the bid process.

- Customer's responsibility should be to contact pre-qualified contractors to request bids.

- The customer is responsible to select, hire, and pay the contractor's costs.

- The customer is responsible to administer the contract or to pay the distributor to do this activity of a "fee for service" basis.

- The distributor shall reimburse the customer for the construction costs less the amount of capital contribution that is determined that the customer should pay.

Voter Summary

The group was split on endorsing option 1 or option 2. The group resolved to put forward both option 1 and option 2 for the Board's review.

The results of the vote on the options is listed:

- Option Two - 6 votes
- Option Three - 4 votes
- Option One - 1 vote

Dissenting Opinions

Discussed above.

APPENDIX A
Pre-qualification

1. WORK EXPERIENCE
    - Number of years in business
    - Type of jobs done previously
    - Number of jobs done previously
    - $ value of jobs done previously
    - Type of work for which they are requesting to be approved

2. EMPLOYEE QUALIFICATIONS
    - Are all staff company employees or are they under contract?
    - Key personnel in the company – names and areas of expertise
    - Years of experience of staff in related areas and their certification

3. COMPANY SAFETY POLICY AND PROGRAM
    - In-house Health & Safety Committee or representative (as per OHSA)
    - Do they have a safety policy?
    - Details of policies or programs
    - Safety association affiliation

4. WORKPLACE SAFETY and INSURANCE BOARD & SAFETY RECORD
    - WSIB firm profile
    - Letter of good standing
    - Experience rating
    - Safety record

5. EQUIPMENT & TOOLS
    - List of vehicles, major equipment and tools available to do the work
    - Are these owned, rented, or leased?

6. PERSONAL PROTECTIVE EQUIPMENT
    - Statement of availability – types and quantities

7. LIABILITY INSURANCE
    - Type of insurance
    - Limits of insurance per occurrence and aggregate

8. BONDING
    - Agreement to bond as required

9. TRAINING
    - Training – are staff certified in their trade by a recognized organization
    - Has staff received update training?

10. PROOF OF RELATED INDUSTRY MEMBERSHIP

    Examples:
    - Construction Safety Association of Ontario (CSAO)
    - Electrical Contractors Association of Ontario (ECAO)
    - Electrical & Utilities Safety Association (E&USA)
    - Industrial Accident Prevention Association (IAPA)
    - Municipal Electric Association (MEA)

11. FINANCIAL STATEMENT OR REPORT
    - Financial capability (references)

12. REFERENCE CHECKS
    - Names of companies for which work has previously been done
    - Interviews with applicant

Note: the distributor should also call other companies not listed as references

2.13 TRANSFORMATION STATION POINT OF OPERATIONAL DEMARCATION

[FINALIZED: MARCH 20, 2000]

Issue Statement

In recognition of the new regulatory framework, that manages accountability issues through license and code requirements, it is seen as useful to examine how we should treat the responsibilities and obligations of licensed distribution and transmission companies to each other. This summary of recommendation specifically deals with protection and control equipment located at transformer stations.

It is worth noting at the outset that recommendations from the DSC Task Force deal only with issues intended for the DSC, which cannot impose conduct rules on transmission companies. Any cross over issues into the transmission system code should be communicated to the TSC Task Force for inclusion in their deliberations.

Protection elements and control elements of the electrical system are often embodied in the same equipment. Breaker settings at a transformer station are designed to protect up-stream equipment, whereas control elements such as auto-reclosures are designed to reduce outage time to downstream equipment. Breaker points with auto or remote control features actually have design elements that serve the interests of both the up-stream equipment owners, by way of protection, and downstream owners, by way of control.

Protection and control of the system where this dual-purpose equipment lies on one side or the other of the ownership demarcation would serve the system better if an operation agreement were in place. In absence of an agreement, either the transmission or distribution company may be incensed by performance requirements to install redundant equipment, injecting inefficiencies into the overall system.

Options

1. The DSC should remain silent on the issue, leaving the concept of entering into an operating agreement to the distributors discretion.

2. The DSC should require that the distributor pursue an operating agreement with the transmission company.

3. The DSC should require that the distributor pursue an operating agreement with the transmission company and specify its content.

Background Information

Supervisory control and data acquisition (SCADA) systems are often utilized by distribution and transmission companies to improve reliability in a cost effective manner. As the name suggests, these systems have either pre-programmed or remote control attributes as well as data gathering capabilities.

The protection and control devices referred to in the issues statement are integral to both distribution and transmission systems for reasons previously described. Scada system interrogation and control points are often utilized on these devises to maximize their value to the systems.

In the majority of cases, the protection and control equipment is owned and operated by the transmission companies. In some cases the protection and control equipment is owned and operated by the distribution company. Due to the current licensing arrangements being worked out, some companies that provide, by definition, distribution and transmission services own and operate both sides of the system.

In dealing with the point of demarcation between the distribution company's system and the end use customer's system, the task force developed a summary of recommendation on the need for an operational versus an ownership demarcation point. It was seen as advantageous to suggest perusal by a distributor of an operations agreement with a customer that would contain details of operations and control of specified apparatus, regardless of what side of the ownership demarcation point the equipment is.

Summary of Discussion

With performance based accountabilities being introduced along with their associated tangible impacts, business cases will be developed that concentrate on the value of maintaining or introducing processes that manage protection and control devises.

In the absence of an operating agreement on a common piece of equipment distribution and transmission companies may choose to install adjacent equipment that performs the same function.

In that both distribution and transmission companies are regulated monopolies under the jurisdiction of the same regulator, it should be possible to minimize overall system costs through prescription of conduct designed to avoid the installation of redundant equipment.

Operating agreements should be based on actual costs to provide service from one entity to the other recognizing that monopoly ownership of equipment negates market forces that would normally be used to establish commercial value. The existing equipment has been paid for revenues bundled in the cost of power in the previous closed market.

Details of any operating agreement should be left to the parties involved, recognizing local requirements and capabilities.

Recommendation

1. The DSC should require that all distributors, that are directly connected to the transmission grid, pursue an operating agreement with the transmission company.

2. And further, that the associated costs related to any provision of service contained in such agreements will be at actual cost of provision.

3. And further that this summary of recommendation be brought to the attention of the TSC Task Force.

Voter Summary

Unanimous.

Dissenting Opinions

None.